PB-220 376

# Characterization of Claus Plant Emissions

Processes Research, Inc.

prepared for

Environmental Protection Agency

APRIL 1973

Distributed By:

NTIS

National Technical Information Service
U. S. DEPARTMENT OF COMMERCE

**EPA-R2-73-188**

PB 220 376

**April 1973**

**Environmental Protection Technology Series**

# Characterization of Claus Plant Emissions

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U S Department of Commerce
Springfield VA 22151

**Office of Research and Monitoring**
**U.S. Environmental Protection Agency**
**Washington, D.C. 20460**

EPA-R2-73-188

# Characterization of Claus Plant Emissions

by

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Contract No. 68-02-0242, Task No. 2
Program Element No. 1A2013

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Prepared for

OFFICE OF RESEARCH AND MONITORING
U. S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

April 1973

This report has been reviewed by the Environmental Protection Agency and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

**BIBLIOGRAPHIC DATA SHEET**

1. Report No. EPA-R2-73-188

2\.

3. Recipient's Accession No. PB-220 376

4. Title and Subtitle
Characterization of Claus Plant Emissions

5. Report Date April 1973

6\.

7. Author(s) W.D. Beers

8. Performing Organization Rept. No.

9. Performing Organization Name and Address
Processes Research, Inc.
2912 Vernon Place
Cincinnati, Ohio 45219

10. Project/Task/Work Unit No. Task Order 2

11. Contract/Grant No. 68-02-0242

12. Sponsoring Organization Name and Address
EPA, Office of Research and Monitoring
NERC/RTP, Control Systems Laboratory
Research Triangle Park, North Carolina 27711

13. Type of Report & Period Covered Final

14\.

15. Supplementary Notes

16. Abstracts

The report discusses Claus sulfur plant emissions and control, based on literature, supplemented with data from companies operating or designing Claus plants. It discusses process variations, investment, and operating costs. It lists data for 169 Claus plants in 31 states, with daily sulfur capacities totaling over 15,800 long tons, most based on natural gas or petroleum refining. Total capacity of 66 Canadian plants is 60 percent more than the U.S. total. Tail gases from Claus plants are usually burned, converting the H2S to sulfur oxides. Annual emissions from U.S. plants are estimated to be 875,000 short tons of SO2 equivalent. Additional catalytic stages could eliminate about 70 percent of these emissions. The Beavon or Cleanair process could eliminate about 99 percent of the emissions, doubling investment and operating costs. The IFP process could eliminate about 90 percent of the emissions; investment and operating costs for the IFP addition are about half of those for the Claus plant alone. Information on the Chiyoda and the Wellman-Power flue gas desulfurization processes are also presented. A bibliography is included.

17. Key Words and Document Analysis. 17a. Descriptors

Air Pollution
*Operating Costs
Desulfurization
Design
*Investments
Economics
Natural Gas
Petroleum Refining
Sulfur Oxides
Hydrogen Sulfide
Catalysis

17b. Identifiers/Open-Ended Terms

Air Pollution Control
Stationary Sources
*Claus Plant
Tail Gases
Beavon Process
Cleanair Process
IFP Process
Chiyoda Process
Wellman-Power Process

17c. COSATI Field/Group 13B

18. Availability Statement Unlimited

19. Security Class (This Report) UNCLASSIFIED

20. Security Class (This Page) UNCLASSIFIED

21. No. of Pages 167/173

22. Price

ii a

## ACKNOWLEDGMENT

The author wishes to acknowledge the assistance of Messrs. R. I. Tarver and G. N. Thomas in the development of this report, the helpful guidance and critique by Messrs. G. S. Haselberger and M. R. Jester, and the contributions to the report by firms whose information appears in the Appendix. In addition, the author wishes to acknowledge the many sources of information used and referred to in the Bibliography.

W. D. Beers

PREC LANK

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## SECTION I - INTRODUCTION

Claus plants produce sulfur from hydrogen sulfide and sulfur dioxide by gas phase reactions. Numerous Claus sulfur plants are operated in the United States in connection with natural gas and petroleum refining.

Because of the apparent potential for atmospheric pollution from unconverted hydrogen sulfide and sulfur dioxide in Claus plant tail gas, a survey was undertaken to collect information concerning Claus sulfur plant emissions and control.

The present report is based on review of literature, supplemented with data from companies operating and/or designing Claus plants.

In view of the rapid pace at which changes are taking place in Claus plant technology and applications, the plant inventories and bibliography presented in this report should be dated. The inventory of Claus plants in Canada was completed in December 1971. The inventory of Claus plants in the United States, and the bibliography were completed in June 1972, based on current publications.

## SECTION II - SUMMARY

Claus sulfur plants convert hydrogen sulfide and sulfur dioxide to sulfur by gas phase reactions near atmospheric pressure, using catalysts in the final stages. A number of Claus process variations are used to accommodate various concentrations of acid gas feed.

There are 169 Claus sulfur plants in the United States having rated daily capacities totaling over 15,800 long tons. Most of these plants are based on acid gas from natural gas or petroleum refining.

Claus plants are found in 31 states. The number in each state is shown on the map of the United States in Appendix A.

The tail gas from a Claus plant contains hydrogen sulfide ($H_2S$) and sulfur dioxide ($SO_2$), but the tail gas is usually burned, converting the $H_2S$ to sulfur oxides. The annual emissions from Claus sulfur plants in the United States are estimated to total 875,000 short tons of $SO_2$ equivalent. The estimated Claus plant emission for each state is shown on the map in Appendix A.

These estimates assume that the Claus sulfur production averages 60 percent of the rated plant capacity and that the Claus sulfur recovery averages 90 percent. Additional catalytic stages could increase the Claus sulfur recovery to about 97 percent, eliminating 70 percent of the Claus plant emissions.

The Beavon Sulfur Removal Process and the Cleanair Sulfur Process are claimed to increase sulfur recovery to more than 99.9 percent, eliminating about 99 percent of Claus plant sulfur emissions. The investment and operating costs for Claus-Beavon plants or Claus-Cleanair plants are about twice those for Claus plants alone. Hence, the production costs for Claus-Beavon sulfur or Claus-Cleanair sulfur are about twice those for Claus sulfur.

The Institut Francais du Petrole (IFP) Process is claimed to increase the sulfur recovery to more than 99 percent, eliminating about 90 percent of Claus plant emissions. The investment and operating costs for an IFP addition is about half of those for the Claus sulfur plant alone. Accordingly, the production costs for Claus-IFP sulfur are about 50 percent higher than those for Claus sulfur.

## SECTION III - CLAUS SULFUR PLANT TECHNOLOGY

Claus plants produce elemental sulfur from the $H_2S$ in acid gas obtained principally from natural gas and petroleum refining. They are named after an English chemist, C. F. Claus, who, about 1885, initiated development of the gas phase process used in such plants.

The number of Claus sulfur plants in each state and annual sulfur emissions are shown on the map of the United States in Appendix A. The basis of the Claus plant emissions shown is explained later in this report.

### A. CLAUS PROCESS VARIATIONS

Flow diagrams presented in Appendix B are typical of the four principal variations used in Claus sulfur plants in the United States, as follows:

Direct oxidation
Split flow
Straight through
Sulfur recycle

These are gas phase processes as distinguished from liquid phase processes such as the Deal-Sulfolane (Shell Oil Company), Giammarco-Vetrocoke, Ferrox, Lacy-Keller, Perox, Stretford, Thylox, and Townsend processes for producing elemental sulfur from $H_2S$.

A Claus sulfur plant usually operates near atmospheric pressure with only enough extra pressure to overcome the pressure drop through the plant.

1. Direct Oxidation. In the original Claus process, called "direct oxidation," $H_2S$ was partially oxidized with air over a bauxite or iron ore catalyst in a single reactor, as follows:

$$3H_2S + 1.5O_2 \longrightarrow 3S + 3H_2O + 159{,}000 \text{ calories}$$

Excessive temperatures experienced with this highly exothermic reaction resulted in poor yields. This soon led to partial recycle of the tail gas to control the temperatures for acceptable yields.

This process is used in modern plants having dilute acid gas feed. The sulfur recovery is increased by adding catalytic stages.

2. Split Flow. About 1937, I. G. Farbenindustrie A. G. initiated two improvements in the Claus process, one or the other of which appears in many Claus plants in the United States. In the first of these, called "split flow," one third of the $H_2S$ is burned completely to sulfur dioxide ($SO_2$) in a waste heat boiler, as follows:

$$H_2S + 1.5O_2 \longrightarrow SO_2 + H_2O + 131{,}000 \text{ calories}$$

The $SO_2$ is then reacted with the other two thirds of the $H_2S$ over bauxite at about 385C, as follows:

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O + 28{,}000 \text{ calories}$$

Thus, only about one fifth of the heat is evolved in the catalytic reactor. Satisfactory temperatures are attained in much smaller reactors, and much of the heat of combustion is recovered as useful steam.

3. Straight Through. The second I. G. Farben improvement, called "straight through," is the noncatalytic partial oxidation of the $H_2S$ to sulfur with air at temperatures up to 1000C in a waste heat boiler. About 60 percent conversion to sulfur is achieved, and the flue gas is cooled and passed to the catalytic reactor for the remaining conversion. In this variation of the Claus

Process, much of the reaction heat is recovered as useful steam, and some sulfur may be condensed from the flue gas to improve the conversion in the catalytic reactor.

4. Sulfur Recycle. The acid gas streams feeding Claus plants sometimes contain so little $H_2S$ that reaction temperatures cannot be maintained without supplemental heat. This gives rise to additional Claus plant variations, including addition of hydrocarbons to acid gas ahead of the burner and/or indirect preheating of the acid gas and/or air ahead of the burner or catalytic reactor.

One Claus plant variation, particularly useful for dilute acid gas having low sulfur oxide content, is called "sulfur recycle." In this, some product sulfur is burned with air to produce $SO_2$ and heat.

The acid gases fed to Claus plants in the United States usually contain little or no sulfur oxides, because they are from the "sweetening" units of natural gas plants and petroleum refineries. These sweetening units usually capture the $H_2S$ and the carbon dioxide, but seldom remove sulfur oxides from the natural gas or refinery gas.

On the other hand, the acid gas fed to a Claus plant from a smelter contains sulfur oxides as well as $H_2S$. The "direct oxidation" process probably would be ideal for such a feed gas.

5. Conversion Incomplete. The Claus Process reactions are reversible, and complete conversion to sulfur is prevented by the sulfur vapor and water vapor produced. Attempts to improve conversion by operating the catalytic reactors at temperatures below the sulfur dewpoint have not succeeded. The liquid

sulfur apparently blocks the catalyst. Instead, improved conversion is achieved by condensing sulfur from the gas stream between Claus stages. With a dilute acid gas stream feeding a Claus plant, less sulfur need be condensed between the Claus stages to keep the sulfur dewpoints below the catalyst surface temperatures. Nevertheless, improved conversion for such a dilute feed will still result from condensing sulfur between Claus stages. In a modern Claus plant, more than half of the sulfur is condensed ahead of the final catalytic stage.

Removal of water vapor to improve conversion to sulfur has also been tried by condensing water from the gas stream between catalytic stages. Because of plugging and highly corrosive conditions, these attempts have all been unsuccessful.

6. Reheat Variations. The reheating of the gas stream after condensing sulfur presents several Claus plant variations, as follows:

a. External-fired heat exchange.

b. Internal gas-to-gas heat exchange.

c. Injection of hot gas from hydrogen sulfide burner.

d. Injection of hot gas from a hydrocarbon burner.

e. Injection of hot gas from upstream.

While the choice of reheating methods is important in adapting the Claus Process to particular plant circumstances, these variations appear to have little effect on the sulfur recovery efficiency of Claus plants.

## B. FEED GAS CONCENTRATION

1. Process Choice. The optimum process arrangement for a Claus plant depends largely on the hydrogen sulfide concentration in the acid gas feed. For

high $H_2S$ concentrations, such as 90 mole percent, the "straight through" process is preferred. For intermediate concentrations, such as 50 mole percent $H_2S$, the "split flow" process is suitable. Low $H_2S$ concentrations, such as 15 mole percent, favor the "direct oxidation" process, or sometimes the "sulfur recycle" process.

2. Claus Plant Costs. The greater gas volumes involved with more dilute acid gas increase the Claus plant investment and sulfur production costs somewhat. For typical Claus plants, each to produce 100 long tons of sulfur daily, the investment and sulfur production costs for various acid gas concentrations are approximately as follows:

| Mole Percent $H_2S$ In Acid Gas Feed | Claus Plant Investment | Sulfur Production Cost Per Long Ton |
|---|---|---|
| 15 | $1,400,000 | $14 |
| 50 | $1,000,000 | $11 |
| 90 | $ 900,000 | $ 9 |

### C. PRODUCT SULFUR CAPACITY

Product sulfur capacity has a more pronounced effect on Claus plant investment and sulfur production costs. For typical Claus plants fed with 50 mole percent $H_2S$ feed gas, the investment and sulfur production costs for various capacities are approximately as follows:

| Product Sulfur Daily Capacity (Long Tons) | Claus Plant Investment | Sulfur Production Cost Per Long Ton |
|---|---|---|
| 10 | $ 300,000 | $26 |
| 100 | $1,000,000 | $11 |
| 1000 | $4,300,000 | $ 8 |

## D. CLAUS SULFUR RECOVERY

The percent conversion to sulfur is affected by the number of catalytic stages in Claus plants. For Claus plants fed with 90 mole percent $H_2S$, the sulfur recovery variation relative to the number of catalytic stages is approximately as follows:

| Number of Catalytic Stages | Percent Sulfur Recovery |
|---|---|
| 1 | 85 |
| 2 | 94 |
| 3 | 97 |

The percentage of sulfur recovery also varies with the concentration of the acid gas fed to the Claus plant. For Claus plants having two catalytic stages, the sulfur recoveries for various acid gas concentrations are approximately as follows:

| Mole Percent $H_2S$ In Acid Gas Feed | Percent Sulfur Recovery Two Catalytic Stages |
|---|---|
| 15 | 90 |
| 50 | 93 |
| 90 | 94 |

## E. CLAUS TAIL GAS

The unrecovered sulfur appears in the Claus plant tail gas principally as $H_2S$, elemental sulfur, and $SO_2$ with lesser amounts of other sulfur compounds. Some of the early Claus plants vented the tail gas directly to the atmosphere. Others scrubbed the tail gas in towers packed with limestone wetted with water. Incineration of the tail gas is the method most often used in United States Claus plants treating the tail gas. Incineration converts the unrecovered sulfur almost entirely to sulfur oxides.

For a Claus plant recovering 100 long tons of sulfur daily, the incinerator stack gas sulfur dioxide equivalents, for various numbers of catalytic converters, and various acid gas feed concentrations, are approximately as follows:

| Number of Catalytic Stages | Mole Percent $H_2S$ In Acid Gas Feed | Stack Gas $SO_2$ Short Tons Daily |
|---|---|---|
| 1 | 90 | 39 |
| 2 | 15 | 25 |
| 2 | 50 | 17 |
| 2 | 90 | 14 |
| 3 | 90 | 7 |

## F. INFORMATION FROM CLAUS PLANT OPERATING AND DESIGN FIRMS

In response to questionnaire letters, information regarding Claus sulfur plants was submitted by the following operating firms and design firms:

Amoco Production Company
Elcor Chemical Corporation
Shell Oil Company
Stauffer Chemical Company
Ford, Bacon & Davis
The Ralph M. Parsons Company
J. F. Pritchard & Co.

Information submitted by these firms is presented in Appendices E, F, G, H, I, J, and K, respectively.

## SECTION IV - CLAUS SULFUR PLANTS IN THE UNITED STATES

The rated sulfur capacities are published for many United States Claus plants. These are listed in Appendix C. In addition to the operating company names and locations, the Claus plant ages and sources of acid gas feeds are listed for most of the plants. For the 169 plants listed, the rated daily sulfur capacities total more than 15,800 long tons.

### A. CLAUS SULFUR PRODUCTION

The annual sulfur production is published for twenty-three Claus plants based on natural gas, having rated daily sulfur capacities totaling 2,068 long tons. The annual sulfur production from these recently totaled 456,000 long tons. If this proportion is typical for all United States Claus plants, bearing in mind that some are standby and others not yet in operation, the annual sulfur production from United States Claus plants totals approximately 3,500,000 long tons.

### B. CLAUS PLANT EMISSIONS

The acid gas feed composition, number of catalytic stages, and tail gas treatment, if any, are seldom published for United States plants. However, it seems probable that the typical Claus plant in the United States has two catalytic stages and the tail gas is burned.

Assuming that the sulfur recovery averages 90 percent, bearing in mind that many plants appear to have excess sulfur capacity, improving their performance, the annual emissions from United States Claus plants are equivalent to approximately 875,000 short tons of $SO_2$.

**On this basis, the emissions from Claus plants in various areas of the United States are approximately as follows (a plus sign, + , denotes some plant capacity not reported):**

| **Area** | **Number of Claus Plants** | **Combined Daily Sulfur Capacity (Long Tons)** | **Computed Annual Emission $SO_2$ Equivalent (Short Tons)** |
|---|---|---|---|
| **Alabama** | **2** | **386** | **21,400** |
| **Alaska** | **1** | **9** | **500** |
| **Arkansas** | **4** | **185** | **10,200** |
| **Los Angeles** | **14** | **1,794+** | **99,300+** |
| **Other California** | **6** | **902** | **49,900** |
| **Colorado** | **1** | **18** | **1,000** |
| **Delaware** | **2** | **775** | **42,900** |
| **Florida** | **4** | **664** | **36,700** |
| **Hawaii** | **1** | **+** | **+** |
| **Illinois** | **4** | **569** | **31,500** |
| **Indiana** | **3** | **414** | **22,900** |
| **Kansas** | **2** | **44** | **2,400** |
| **Louisiana** | **6** | **570** | **31,500** |
| **Michigan** | **3** | **89** | **4,900** |
| **Minnesota** | **2** | **170** | **9,400** |
| **Mississippi** | **5** | **1,327+** | **73,500+** |
| **Missouri** | **1** | **80** | **4,400** |
| **Montana** | **3** | **233** | **12,900** |
| **New Jersey** | **8** | **647+** | **35,800+** |
| **New Mexico** | **7** | **147** | **8,100** |
| **New York** | **1** | **50** | **2,800** |
| **North Dakota** | **2** | **243** | **13,500** |
| **Ohio** | **3** | **95** | **5,300** |
| **Oklahoma** | **2** | **23** | **1,300** |
| **Pennsylvania** | **6** | **452** | **25,000** |
| **El Paso, Texas** | **2** | **1,009** | **55,800** |
| **Midland, Texas** | **20** | **592** | **32,800** |
| **Lubbock, Texas** | **5** | **93** | **5,200** |
| **Amarillo, Texas** | **3** | **76** | **4,200** |
| **San Antonio, Texas** | **7** | **276** | **15,300** |
| **Corpus Christi, Texas** | **1** | **85** | **4,700** |
| **Houston, Texas** | **5** | **696+** | **38,500+** |
| **Beaumont, Texas** | **5** | **358** | **19,800** |
| **Dallas, Texas** | **10** | **1,685** | **93,300** |
| **Utah** | **2** | **22** | **1,200** |
| **Virginia** | **1** | **50** | **2,800** |
| **Washington** | **1** | **20** | **1,100** |

| Area | Number of Claus Plants | Combined Daily Sulfur Capacity (Long Tons) | Computed Annual Emission $SO_2$ Equivalent (Short Tons) |
|---|---|---|---|
| West Virginia | 1 | 27 | 1,500 |
| Wisconsin | 1 | 15 | 800 |
| Wyoming | 12 | 919 | 50,900 |
| Total United States | 169 | 15,809+ | 875,000+ |
| Total Texas | 58 | 4,870+ | 269,600+ |
| Total California | 20 | 2,696+ | 149,200+ |

The number of Claus plants and annual Claus plant emission for each state are shown on the map of the United States in Appendix A.

## C. COMPANIES OPERATING CLAUS PLANTS

The leading operators of Claus sulfur plants in the United States include the following companies:

Allied Chemical Corporation
Amarillo Oil Company
American Oil Company (Standard Oil Company, Indiana)
Amoco Production Company (Standard Oil Company, Indiana)
Ashland Oil, Inc.
Atlantic Richfield Company
BP Oil Corporation (Standard Oil Company, Ohio)
Chevron Oil Company (Standard Oil Company of California)
Cities Service Oil Company
Continental Oil Company
Getty Oil Company
Gulf Oil Corporation
Humble Oil & Refining Company
Marathon Oil Company
Mobil Oil Corporation
Monsanto Company
Olin Corporation
J. L. Parker Company
Phillips Petroleum Company
Shell Oil Company
Signal Oil & Gas Company
Stauffer Chemical Company
Sun Oil Company
Texaco, Inc.
Union Oil Company of California
Warren Petroleum Corporation

## D. CLAUS PLANT DESIGN FIRMS

A number of firms are experienced designers of Claus sulfur plants in the United States, including the following:

- Black Sivalls & Bryson, Inc.
- Delta Engineering Corporation
- Dresser Engineering Corporation
- Fluor Corporation
- Ford, Bacon & Davis, Inc.
- Howe-Baker Engineers, Inc.
- Hudson Engineering Corporation
- The Ortloff Corporation
- The Ralph M. Parsons Company
- J. F. Pritchard & Company
- Pons Engineers, Inc.
- Stearns-Roger Corporation
- Weatherby Engineering Corporation

## SECTION V - CLAUS SULFUR PLANTS IN CANADA

Information regarding Claus sulfur plants located in Canada is presented in Appendix D. The daily sulfur capacities of the 66 Canadian plants listed total more than 25,400 long tons. This is about 60 percent more than the combined daily sulfur capacity of 169 Claus plants located in the United States.

About 93 percent of the Canadian Claus sulfur capacity is based on Alberta natural gas, and are located upwind of the population centers in the northern United States.

## SECTION VI - REDUCTION OF CLAUS PLANT EMISSIONS

Beyond the addition of Claus catalytic stages, the following methods have been proposed to reduce sulfur emissions from Claus plants in the United States:

Alberta Sulfur Research, Ltd. Sulphoxide Process
Rhodia, Inc. Cataban Process
Union Carbide Process
Chiyoda Thoroughbred 101 Flue Gas Desulfurization Process
Wellman-Lord Sulfur Dioxide Recovery Process
Monsanto NOSOX Process
Takahax Process
Beavon Sulfur Removal Process
Cleanair Sulfur Process
Institut Francais du Petrole Process

The Alberta Sulfur Process, Ltd. Sulphoxide Process is claimed to reduce Claus tail gas sulfur contents to less than 1000 ppm. This process uses an organic sulphoxide as a liquid catalyst medium in which to react the $H_2S$ and $SO_2$ to form elemental sulfur. The COS and $CS_2$ are converted to $CO_2$ and sulfur. The process has been operated in the laboratory. Application to a full-scale plant remains to be done.

The Rhodia, Inc. Cataban Process, which has been developed through the pilot plant stage, uses an aqueous solution of a chelated iron salt as a liquid phase catalyst, oxidizing hydrogen sulfide to elemental sulfur. Texas Gulf Sulfur and another company are reported to be investigating the use of this process for reducing Claus plant sulfur emissions.

The Union Carbide Process is reported as using a new catalyst in an absorptive operation. It is claimed that this process can reduce Claus tail gas sulfur contents to about 50 ppm. Union Carbide Corporation is expected to announce soon further information about this process.

## A. FLUE GAS DESULFURIZATION PROCESSES

Numerous processes being developed for removal of sulfur dioxide from power plant stack gas appear applicable to incinerated Claus tail gas. As the $SO_2$ concentrations are several times higher in incinerated Claus tail gas than in power plant stack gas, the treatment of the incinerated Claus tail gas appears somewhat easier.

1. Two such processes now being vigorously advocated in the United States are the Chiyoda Thoroughbred 101 Flue Gas Desulfurization Process and the Wellman-Lord Sulfur Dioxide Recovery Process.

Information regarding the Chiyoda process was submitted by Chiyoda Chemical Engineering & Construction Co., Ltd., in connection with their advertisement in Hydrocarbon Processing. This information is presented in Appendix L.

Information regarding the Wellman-Lord process was obtained by Environmental Protection Agency personnel on visits to plants in Japan where this process is in operation. This information is presented in Appendix N.

2. Monsanto Enviro-Chem Systems, Inc., is reported to be developing its NOSOX Process to remove sulfur dioxide from incinerated Claus tail gas.

3. Ford, Bacon & Davis has recently been licensed to use the Takahax Process of Tokyo Gas Company. This process is reported to use an alkaline solution to scrub the Claus tail gas and to produce elemental sulfur.

## B. BEAVON SULFUR REMOVAL PROCESS

The Beavon Sulfur Removal Process is reported to have been proven in a pilot plant by cooperation of The Ralph M. Parsons Company and Union Oil Company of California. Union Oil is said to be planning to use this process at their

Los Angeles refinery (Wilmington, California), where Union Oil already has a Claus sulfur plant.

The process is named for David K. Beavon, Director of Process Operations for The Ralph M. Parsons Company.

A flow diagram for this process is presented in Appendix J, together with information submitted by The Ralph M. Parsons Company. The process is claimed to reduce the tail gas sulfur content to 40 to 80 ppm equivalent $SO_2$, depending on the sulfur content of the Claus tail gas before treatment.

In the Beavon Process, the Claus plant tail gas is mixed with hot combustion gas produced by burning fuel gas with air. The resulting reducing mixture is passed through a catalytic reactor resembling that of a Claus plant. On the cobalt-molybdate catalyst, all of the sulfur is hydrogenated to $H_2S$. Water is then condensed from the gas. The cooled gas stream is passed to a Stretford section in which the $H_2S$ is removed from the gas and converted to elemental sulfur. The Stretford process is widely used outside of the United States and one Stretford unit was recently installed at Long Beach, California, to sweeten natural gas.

The Beavon Sulfur Removal Process addition to an existing Claus plant costs about as much as the Claus plant itself. With the doubled fixed costs and added utilities costs, the production cost for Claus-Beavon sulfur is approximately twice that for Claus sulfur. Hence, the inventor is promoting this process, not as an economical method for producing sulfur, but strictly as a pollution abatement alternative.

### C. CLEANAIR SULFUR PROCESS

The Cleanair Sulfur Process of J. F. Pritchard & Co., was developed with Texas Gulf Sulfur Company at the Okotoks, Alberta, Canada Claus sulfur plant. This process is being used in a revision of the sulfur plant in the Gulf Oil Corporation refinery at Philadelphia, Pennsylvania. This process is claimed to reduce the tail gas sulfur content to less than 250 ppm by volume of equivalent $SO_2$ without incineration or dilution. This would indicate an overall Claus-Cleanair sulfur recovery of approximately 99.9 percent.

Information regarding the Cleanair Sulfur Process submitted by J. F. Pritchard & Co., is presented in Appendix K. This process includes a Stretford section, as does the Beavon Sulfur Removal Process already described. The Long Beach, California, Stretford unit previously mentioned was built by J. F. Pritchard & Co.

For a Claus-Cleanair sulfur plant, the investment and operating costs are about twice those for a Claus plant having the same sulfur production capacity.

### D. INSTITUT FRANCAIS DU PETROLE PROCESS

The Institut Francais du Petrole (IFP) Process has been in operation in a Japanese refinery for several months, recovering sulfur from Claus tail gas. Four more IFP units, three in Japan and one in Canada, are reported to be starting operation. Information regarding this process submitted by Institut Francais du Petrole is presented in Appendix M.

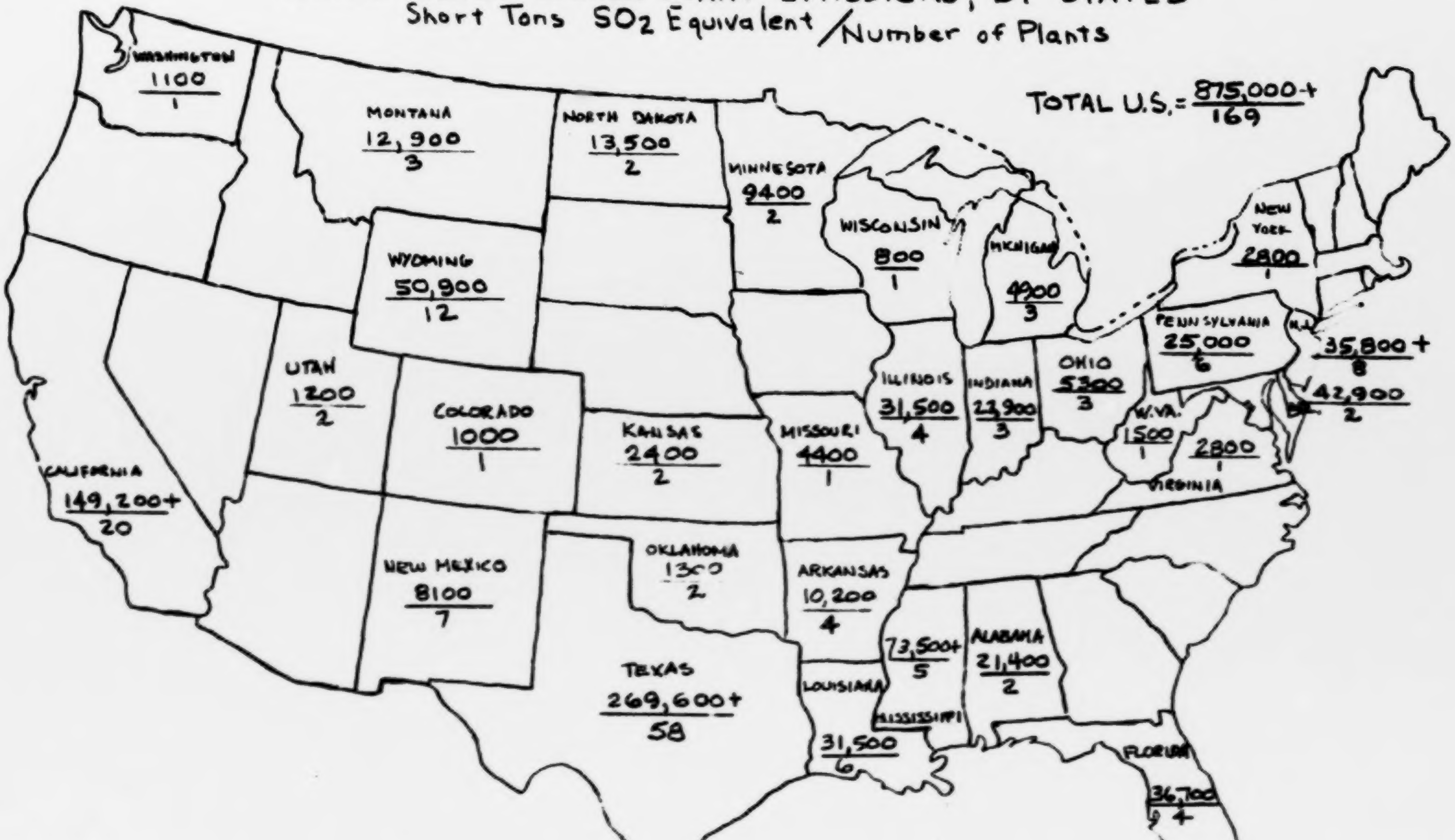
The IFP process is claimed to reduce the incinerator stack gas sulfur content to about 1500 ppm $SO_2$ for an overall Claus-IFP sulfur recovery of about

99 percent. The residual sulfur emission occurs principally because the carbonyl sulfide (COS) and carbon disulfide ($CS_2$) in the Claus tail gas are not converted by the IFP process. The investment and operating costs for an IFP unit are about half of those for the Claus sulfur plant alone. Hence, the addition of the IFP unit results in Claus-IFP sulfur production costs about 50 percent higher than those for Claus sulfur.

# APPENDIX A - MAP OF UNITED STATES CLAUS PLANTS

# ANNUAL CLAUS SULFUR PLANT EMISSIONS, BY STATES

Short Tons $SO_2$ Equivalent/Number of Plants


TOTAL U.S. = 875,000+ / 169
WASHINGTON 1100 / 1
MONTANA 12,900 / 3
NORTH DAKOTA 13,500 / 2
MINNESOTA 9400 / 2
WISCONSIN 800 / 1
MICHIGAN 4900 / 3
NEW YORK 2800 / 1
WYOMING 50,900 / 12
PENNSYLVANIA 25,000 / 6
N.J.
35,800+ / 8
42,900 / 2
UTAH 1200 / 2
COLORADO 1000 / 1
ILLINOIS 31,500 / 4
INDIANA 22,900 / 3
OHIO 5300 / 3
W.VA. 1500 / 1
2800 / 1 VIRGINIA
KANSAS 2400 / 2
MISSOURI 4400 / 1
CALIFORNIA 149,200+ / 20
NEW MEXICO 8100 / 7
OKLAHOMA 1300 / 2
ARKANSAS 10,200 / 4
73,500+ / 5 MISSISSIPPI
ALABAMA 21,400 / 2
TEXAS 269,600+ / 58
LOUISIANA 31,500 / 6
FLORIDA 36,700 / 4

03388 WRD - APRIL 1973

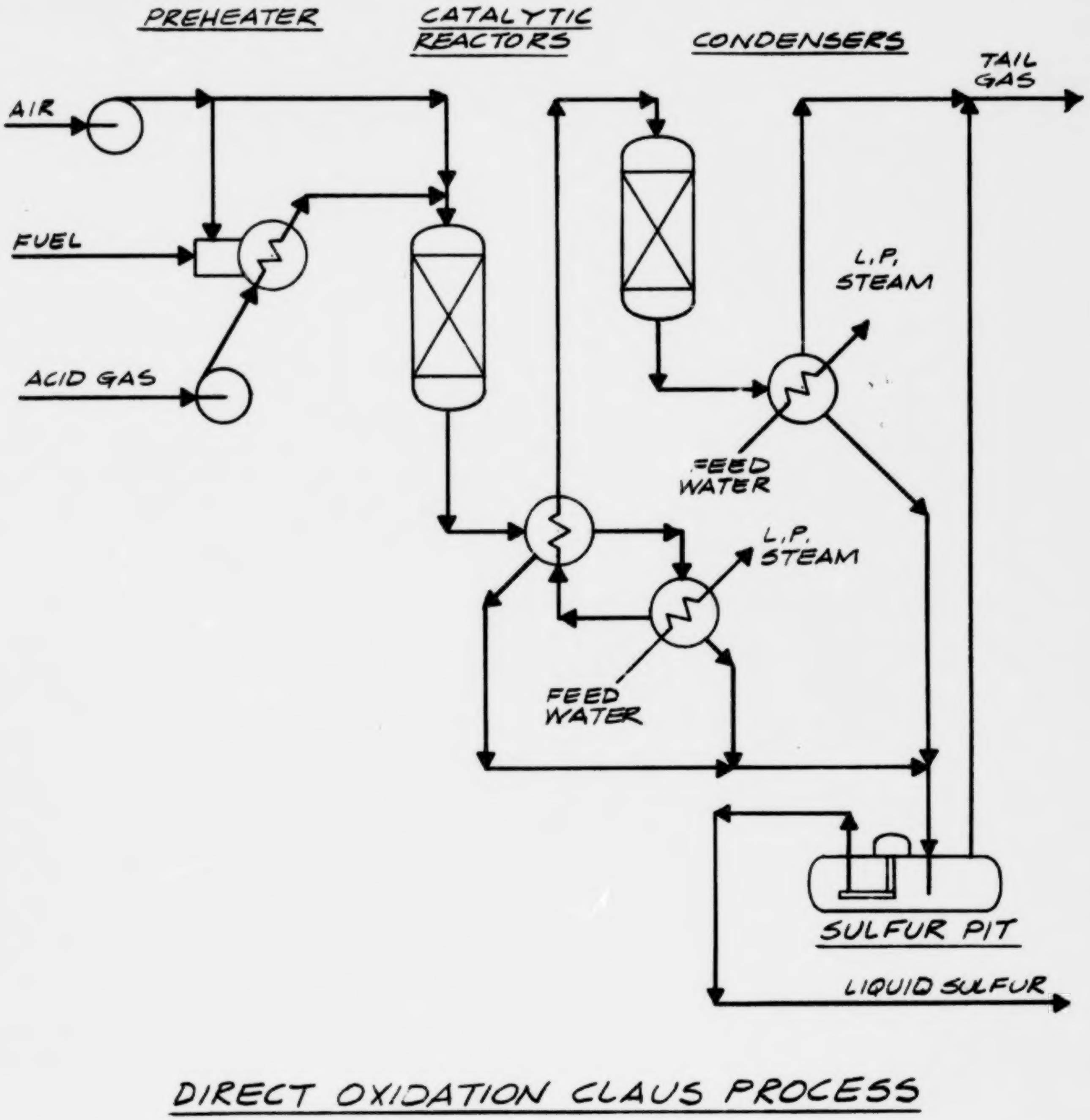
# APPENDIX B - CLAUS PROCESS FLOW DIAGRAMS

PR 109

Job EPA
Location UNITED STATES
Subject CLAUS PLANTS

**PROCESSES RESEARCH, INC.**
INDUSTRIAL PLANNING
AND RESEARCH
CINCINNATI NEW YORK

File No 03388 Sheet No B.1
Checked by ______ Date ______
Computed by WDB Date APRIL 1973


PREHEATER
CATALYTIC REACTORS
CONDENSERS
TAIL GAS
AIR
FUEL
ACID GAS
L.P. STEAM
FEED WATER
L.P. STEAM
FEED WATER
SULFUR PIT
LIQUID SULFUR

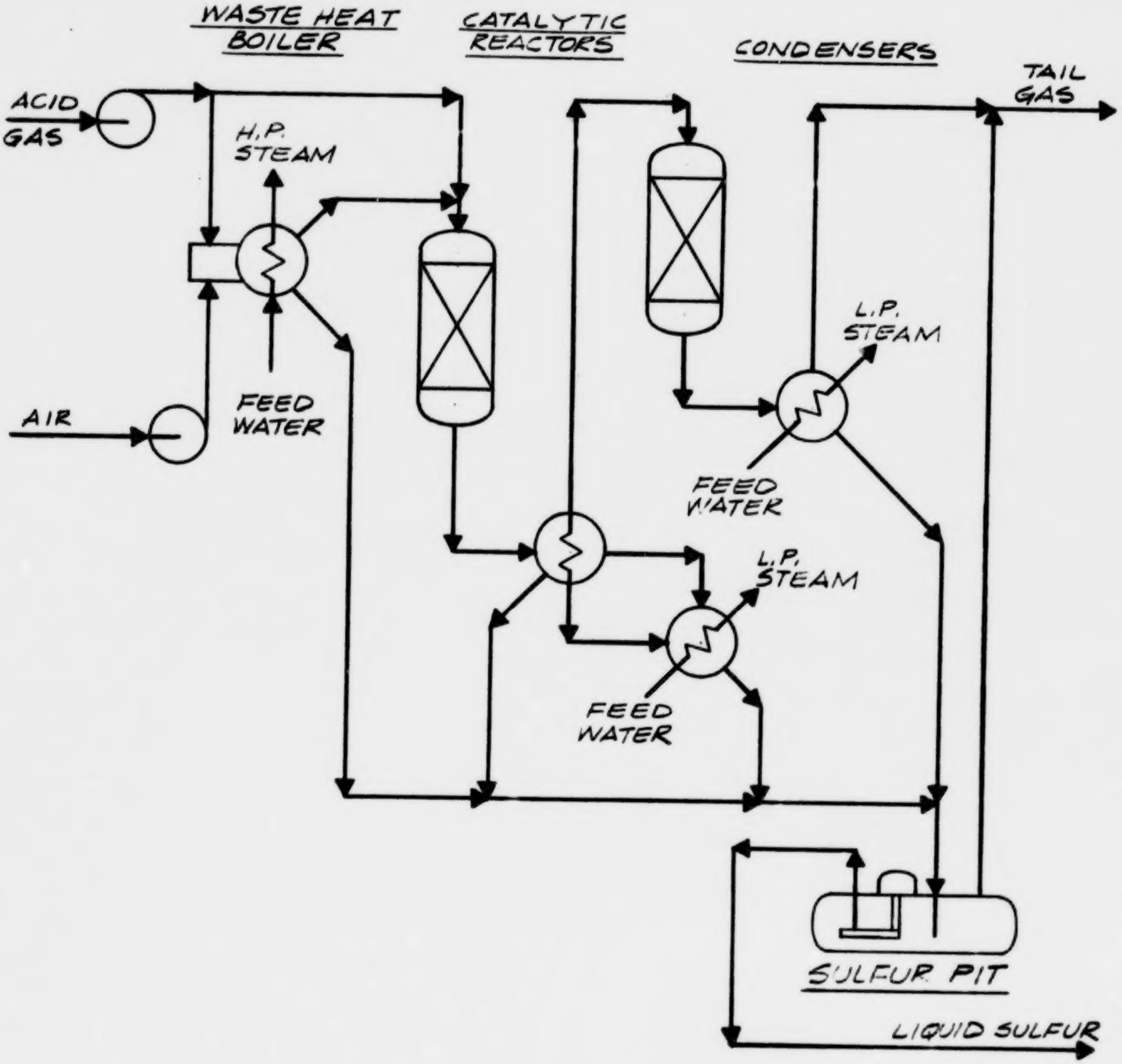
DIRECT OXIDATION CLAUS PROCESS

PR 109

Job EPA
Location UNITED STATES
Subject CLAUS PLANTS

**PROCESSES RESEARCH, INC.**
INDUSTRIAL PLANNING
AND RESEARCH
CINCINNATI NEW YORK

File No 03388 Sheet No 82
Checked by ______ Date ______
Computed by WDB Date APRIL 1973


WASTE HEAT BOILER
CATALYTIC REACTORS
CONDENSERS
ACID GAS
H.P. STEAM
TAIL GAS
AIR
FEED WATER
L.P. STEAM
FEED WATER
L.P. STEAM
FEED WATER
SULFUR PIT
LIQUID SULFUR

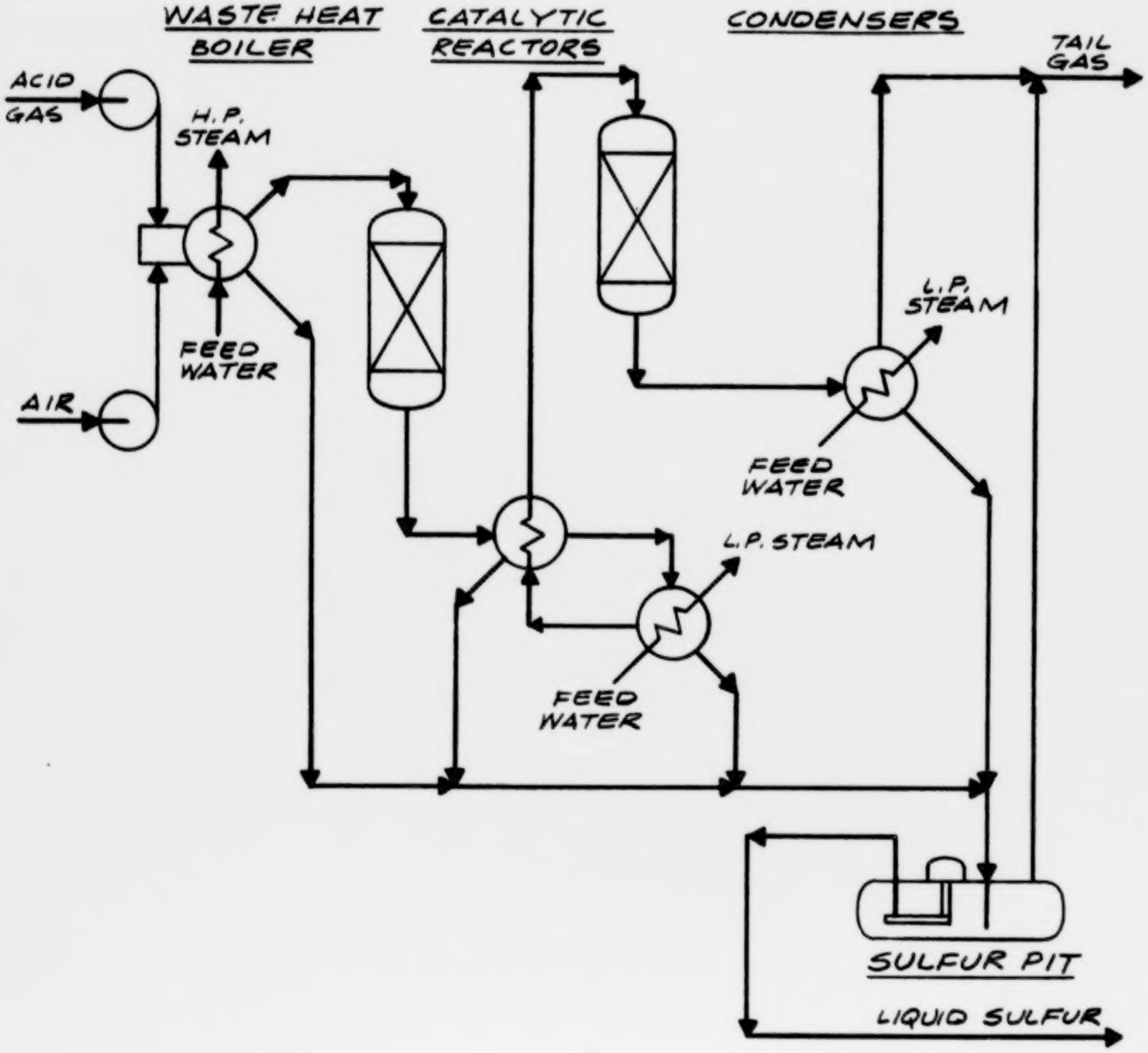
SPLIT FLOW CLAUS PROCESS

PR 109

Job EPA
Location UNITED STATES
Subject CLAUS PLANTS

**PROCESSES RESEARCH, INC.**
INDUSTRIAL PLANNING AND RESEARCH
CINCINNATI NEW YORK

File No 03588 Sheet No 88
Checked by ________ Date ____
Computed by WAB Date APRIL 1973



WASTE HEAT BOILER
CATALYTIC REACTORS
CONDENSERS
TAIL GAS
ACID GAS
H.P. STEAM
FEED WATER
AIR
L.P. STEAM
FEED WATER
L.P. STEAM
FEED WATER
SULFUR PIT
LIQUID SULFUR

STRAIGHT THROUGH CLAUS PROCESS

PR 109

Job EPA

Location UNITED STATES

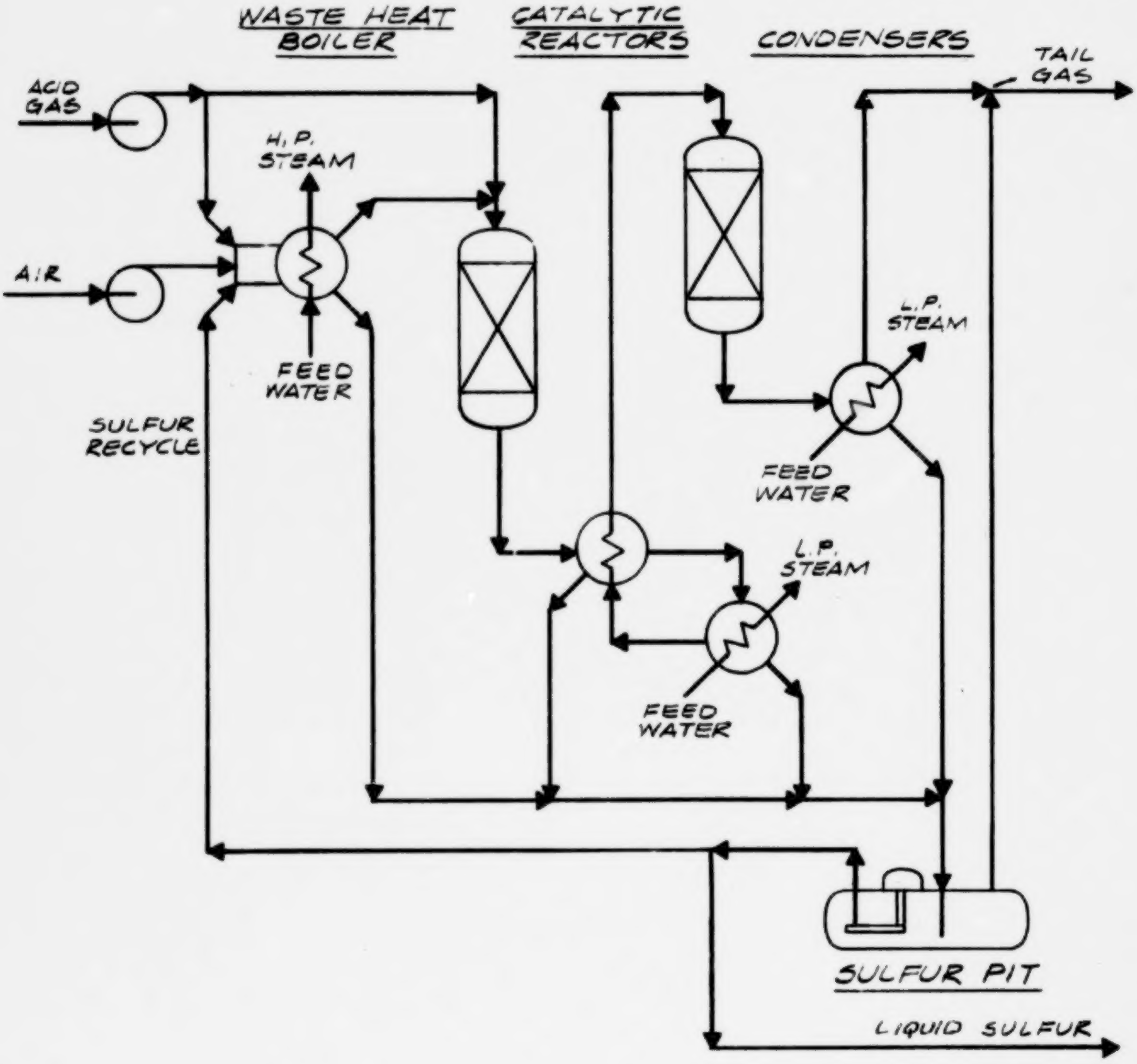
Subject CLAUS PLANTS

**PROCESSES RESEARCH, INC.**
INDUSTRIAL PLANNING
AND RESEARCH
CINCINNATI NEW YORK

File No 03388 Sheet No 84

Checked by ______ Date ______

Computed by WAB Date APRIL 1973


WASTE HEAT BOILER
CATALYTIC REACTORS
CONDENSERS
TAIL GAS
ACID GAS
AIR
H. P. STEAM
FEED WATER
SULFUR RECYCLE
L.P. STEAM
FEED WATER
L.P. STEAM
FEED WATER
SULFUR PIT
LIQUID SULFUR

SULFUR RECYCLE CLAUS PROCESS

# APPENDIX C - CLAUS SULFUR PLANT DATA

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| ALABAMA | | | |
| Humble Oil & Refining Co. | | | |
| Flomaton, Escambia | 1972 | Natural Gas | 136 |
| Stauffer Chemical Co. | | | |
| LeMoyne | Before 1962 | Natural Gas | 127 |
| Expansion | Before 1972 | Natural Gas | +123 |
| ALASKA | | | |
| Energy Co. Alaska | | | |
| Fairbanks, North Star | 1972 | Refinery | 9 |
| ARKANSAS | | | |
| Arkla Chemical Corp. | | | |
| Magnolia, Columbia | Before 1962 | Natural Gas | 19 |
| Expansion | 1962 | Natural Gas | +11 |
| The Bromet Co. | | | |
| Magnolia, Columbia | 1970 | Chemical | 30 |
| Monsanto Co. | | | |
| Eldorado, Union | Before 1961 | Refinery | 25 |
| Olin Corp. | | | |
| McKamie, Lafayette | 1944 | Natural Gas | 100 |
| CALIFORNIA | | | |
| Monsanto Co. | | | |
| Avon | Before 1967 | Refinery | 132 |
| Union Oil Co. of California | | | |
| Santa Maria, Santa Barbara | 1954 | Refinery | 55 |
| Allied Chemical Corp. | | | |
| Richmond, Contra Costa | Before 1962 | Refinery | 100 |
| Expansion | 1968 | Refinery | +100 |
| Humble Oil & Refining Co. | | | |
| Benicia, Solano | 1969 | Refinery | 270 Two Trains |
| Shell Oil Co. | | | |
| Martinez, Contra Costa | 1966 | Refinery | 100 |
| Union Oil Co. of California | | | |
| San Francisco, San Mateo | 1955 | Refinery | 70 |
| Expansion | 1971 | Refinery | +75 |
| Allied Chemical Corp. | | | |
| El Segundo, Los Angeles | 1959 | Refinery | 175 Standby |
| Expansion | 1964 | Refinery | +100 |
| Atlantic Richfield Co. | | | |
| Wilmington, Los Angeles | 1967 | Refinery | 65 |
| Collier Carbon and Chemical Corp. | | | |
| Los Angeles, Los Angeles | Before 1972 | | Not Reported |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| CALIFORNIA | | | |
| Continental Oil Co. | | | |
| Paramount, Los Angeles | 1966 | Refinery | 9 |
| Fletcher Oil & Refining Co. | | | |
| Wilmington, Los Angeles | Before 1962 | Refinery | 7 Standby |
| Golden Eagle Refining Co. Inc. | | | |
| Torrance, Los Angeles | 1959 | Refinery | 4 Standby |
| Gulf Oil Corp. | | | |
| Santa Fe Springs, Los Angeles | Before 1961 | Refinery | 8 |
| Expansion | Before 1962 | Refinery | 9 |
| Expansion | 1964 | Refinery | 13 |
| Lomita Gasoline Co. | | | |
| Long Beach, Los Angeles | 1971 | Natural Gas | Not Reported |
| Mobil Oil Corp. | | | |
| Torrance, Los Angeles | 1967 | Refinery | 85 |
| Expansion | 1973 | Refinery | Not Reported |
| Powerine Oil Co. | | | |
| Santa Fe Springs, Los Angeles | 1967 | Refinery | 20 |
| Standard Oil Company of California | | | |
| El Segundo, Los Angeles | 1972 | Refinery | 450 |
| Stauffer Chemical Co. | | | |
| Wilmington, Los Angeles | Before 1962 | Refinery | 100 |
| Expansion | Before 1962 | Refinery | +20 |
| Expansion | 1962 | Refinery | +140 |
| Expansion | 1964 | Refinery | +8 |
| Expansion | 1967 | Refinery | +132 |
| Expansion | Before 1972 | Refinery | +50 |
| Texaco, Inc. | | | |
| Los Angeles, Los Angeles | Before 1962 | Refinery | 50 |
| Union Oil Co. of California | | | |
| Willmington, Los Angeles | 1952 | Refinery | 49 |
| Expansion | 1962 | Refinery | +100 |
| Expansion | 1973 | Refinery | +200 |
| COLORADO | | | |
| Continental Oil Co. | | | |
| Denver, Adams | 1968 | Refinery | 18 |
| DELAWARE | | | |
| Getty Oil Co. | | | |
| Delaware City, New Castle | 1956 | Refinery | 375 |
| Stauffer Chemical Co. | | | |
| Delaware City, New Castle | Before 1962 | Refinery | 260 |
| Expansion | Before 1972 | Refinery | +140 |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| FLORIDA | | | |
| Amerada Hess Corp. | | | |
| Jay, Santa Rosa | 1972 | Natural Gas | 120 |
| Humble Oil & Refining Co. | | | |
| Jay, Santa Rosa | 1971 | Natural Gas | 14 |
| Expansion | 1972 | Natural Gas | +360 |
| Louisiana Land & Exploration Co. | | | |
| Jay, Santa Rosa | 1972 | Natural Gas | 82 |
| Louisiana Land & Exploration Co. | | | |
| Escambia County | 1972 | Natural Gas | 88 |
| HAWAII | | | |
| Dillingham Petroleum Corp. | | | |
| Barbers Point, Honolulu | 1972 | Refinery | Not Reported |
| ILLINOIS | | | |
| Anilin Company of Illinois | | | |
| Wood River, Madison | 1960 | Refinery | 150 |
| Marathon Oil Co. | | | |
| Robinson, Crawford | 1970 | Refinery | 40 |
| Mobil Oil Corp. | | | |
| Joliet, Will | 1972 | Refinery | 300 |
| Union Oil Co. of California | | | |
| Lemont, Cook | Before 1961 | Refinery | 20 |
| Expansion | 1964 | Refinery | +34 |
| Expansion | 1971 | Refinery | +25 |
| INDIANA | | | |
| American Oil Co. | | | |
| Whiting, Lake | 1952 | Refinery | 64 |
| Expansion | 1964 | Refinery | +40 |
| Expansion | 1972 | Refinery | +43 |
| Expansion | 1972 | Refinery | +132 |
| Atlantic Richfield Co. | | | |
| East Chicago, Lake | 1971 | Refinery | 85 |
| Cities Service Oil Co. | | | |
| East Chicago, Lake | 1972 | Refinery | 50 |
| KANSAS | | | |
| Farmland Industries, Inc. | | | |
| Coffeyville, Montgomery | 1968 | Refinery | 6 |
| Phillips Petroleum Co. | | | |
| Kansas City | 1968 | Refinery | 38 |
| LOUISIANA | | | |
| Cities Service Oil Co. | | | |
| Lake Charles, Calcasieu | 1972 | Refinery | 100 |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| LOUISIANA | | | |
| Gulf Oil Corp. | | | |
| Belle Chasse, Plaquemines | 1972 | Refinery | 40 |
| Humble Oil & Refining Co. | | | |
| Baton Rouge | 1967 | Refinery | 10 |
| Expansion | 1972 | Refinery | +300 |
| Stauffer Chemical Co. | | | |
| Baton Rouge | 1950 | Refinery | 30 |
| Shell Oil Co. | | | |
| Norco, St. Charles | 1965 | Refinery | 40 |
| Texaco, Inc. | | | |
| Paradis, St. Charles | 1966 | Refinery | 50 |
| MICHIGAN | | | |
| Leonard Refineries, Inc. | | | |
| Alma, Gratiot | 1956 | Refinery | 12 |
| Marathon Oil Co. | | | |
| Detroit | Before 1961 | Refinery | 27 |
| Expansion | 1962 | Refinery | +8 |
| Expansion | 1968 | Refinery | +34 |
| Mobil Oil Corp. | | | |
| Woodhaven, Trenton | 1962 | Refinery | 8 |
| MINNESOTA | | | |
| Great Northern Oil Co. | | | |
| Pine Bend | 1955 | Refinery | 60 |
| Expansion | 1963 | Refinery | +70 |
| North Western Refining Co. | | | |
| St. Paul Park, Washington | 1968 | Refinery | 40 |
| MISSISSIPPI | | | |
| Elcor Chemical Corp. | | | |
| Canton, Madison | 1965 | Natural Gas | 12 Standby |
| Shell Oil Co. | | | |
| Jackson | 1972 | Natural Gas | 1250 |
| Gulf Oil Corp. | | | |
| Purvis, Lamar | Before 1961 | Refinery | 30 |
| Shell Oil Co. | | | |
| Goodwater, Clarke | 1971 | Natural Gas | 35 |
| Chevron Oil Co. | | | |
| Pascagoula, Jackson | 1972 | Refinery | Not Reported |
| MISSOURI | | | |
| American Oil Co. | | | |
| Sugar Creek, Jackson | 1971 | Refinery | 80 |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| MONTANA | | | |
| Farmers Union Central Exchange | | | |
| Laurel, Yellowstone | 1969 | Refinery | 28 |
| Montana Sulfur & Chemical Co. | | | |
| East Billings, Yellowstone | Before 1972 | Refinery | 120 Standby |
| Montana Sulfur & Chemical Co. | | | |
| Billings, Yellowstone | 1956 | Refinery | 40 |
| Expansion | 1964 | Refinery | +45 |
| NEW JERSEY | | | |
| Allied Chemical Corp. | | | |
| Elizabeth, Union | 1958 | Refinery | 30 Standby |
| American Cyanamid Co. | | | |
| Bound Brook, Somerset | 1967 | Refinery & Chemical | 12 |
| Expansion | 1972 | | Not Reported |
| American Cyanamid Co. | | | |
| Linden, Union | 1972 | Chemical | Not Reported |
| Anilin Company of New Jersey | | | |
| Perth Amboy, Middlesex | 1957 | Refinery | 35 |
| Expansion | 1962 | Refinery | +15 |
| Amerada Hess Corp. | | | |
| Port Reading, Middlesex | Before 1967 | Refinery | 40 |
| Humble Oil & Refining Co. | | | |
| Linden, Union | 1970 | Refinery | 300 Two Trains |
| Freeport Sulfur Co. | | | |
| Westville, Camden | Before 1961 | Refinery | 30 |
| Mobil Oil Corp. | | | |
| Paulsboro, Camden | Before 1961 | Refinery | 95 |
| Expansion | 1972 | Refinery | +90 |
| NEW MEXICO | | | |
| Amoco Production Co. | | | |
| Artesia, Eddy | 1960 | Natural Gas | 26 |
| Cities Service Oil Co. | | | |
| Milnesand, Roosevelt | 1967 | Natural Gas | 20 |
| Climax Chemical Co. | | | |
| Oil Center, Lea | 1962 | Natural Gas | 18 |
| El Paso Natural Gas Co. | | | |
| Eunice, Lea | Before 1961 | Refinery | 30 |
| Marathon Oil Co. | | | |
| Indian Basin, Eddy | 1967 | Natural Gas | 36 |
| Northern Gas Products Co. | | | |
| Hobbs, Lea | 1969 | | 13 |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| NEW MEXICO | | | |
| Warren Petroleum Corp. | | | |
| Tatum, Lea | 1961 | Natural Gas | 4 |
| NEW YORK | | | |
| Ashland Oil, Inc. | | | |
| Buffalo | 1969 | Refinery | 50 |
| NORTH DAKOTA | | | |
| Signal Oil & Gas Co. | | | |
| Tioga, Williams | 1953 | Refinery | 50 |
| Expansion | 1963 | Refinery | +23 Standby |
| Expansion | 1967 | Refinery | +150 |
| Texaco, Inc. | | | |
| Lignite, Burke | 1961 | Natural Gas | 20 |
| OHIO | | | |
| Ashland Oil, Inc. | | | |
| Canton, Stark | 1970 | Refinery | 50 |
| Republic Steel Corp. | | | |
| Cleveland, Cuyahoga | 1961 | Chemical | 6 |
| Sun Oil Co. | | | |
| Toledo | 1958 | Refinery | 12 |
| Expansion | 1972 | Refinery | +27 |
| OKLAHOMA | | | |
| Pioneer Natural Gas Co. | | | |
| Madill, Marshall | 1967 | Natural Gas | 8 |
| J. L. Parker Co. | | | |
| Madill, Marshall | Before 1961 | Natural Gas | 15 Standby |
| PENNSYLVANIA | | | |
| Atlantic Richfield Co. | | | |
| Marcus Hook, Delaware | Before 1961 | Refinery | 20 |
| Expansion | 1962 | Refinery | +32 |
| Atlantic Richfield Co. | | | |
| Philadelphia, Philadelphia | 1964 | Refinery | 38 |
| Expansion | 1971 | Refinery | +35 |
| BP Oil Corp. | | | |
| Marcus Hook, Delaware | Before 1972 | Refinery | 52 |
| Gulf Oil Corp. | | | |
| Philadelphia, Philadelphia | Before 1961 | Refinery | 135 |
| Sun Oil Co. | | | |
| Marcus Hook, Delaware | 1955 | Refinery | 30 |
| United States Steel Corp. | | | |
| Pittsburgh, Allegheny | Before 1967 | Chemical | 110 |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| **TEXAS** | | | |
| American Smelting and Refining Co. | | | |
| El Paso, El Paso | 1972 | Smelter | 9 Pilot Plant |
| Elcor Chemical Corp. | | | |
| Van Horn, Culbertson | 1969 | Gypsum | 1000 Standby |
| Amarillo Oil Co. | | | |
| Waha, Pecos | 1971 | Natural Gas | 2 |
| Marathon Oil Co. | | | |
| Raan, Pecos | 1967 | Natural Gas | 13 |
| Mobil Oil Corp. | | | |
| Coyanosa, Pecos | 1967 | Natural Gas | 29 |
| Texas American Sulfur Co. | | | |
| Sand Hills, Crane | 1966 | Natural Gas | 15 |
| Phillips Petroleum Co. | | | |
| Crane County | Before 1961 | Natural Gas | 100 |
| Expansion | 1962 | Natural Gas | +65 |
| Warren Petroleum Corp. | | | |
| Waddell, Crane | Before 1961 | Natural Gas | 50 |
| Expansion | 1968 | Natural Gas | +45 |
| Warren Petroleum Corp. | | | |
| San Hills, Crane | 1964 | Natural Gas | 50 |
| Northwest Production Corp. | | | |
| Big Lake, Reagan | Before 1962 | Natural Gas | 3 |
| Expansion | 1962 | Natural Gas | +5 |
| Sid Richardson Carbon & Gasoline Co. | | | |
| Kermit, Winkler | Before 1961 | Natural Gas | 5 |
| Wanda Petroleum Co. | | | |
| Kermit, Winkler | 1967 | Natural Gas | 18 |
| Amarillo Oil Col. | | | |
| Goldsmith, Ector | 1967 | Natural Gas | 5 |
| Amoco Production Co. | | | |
| North Cowden, Ector | 1952 | Natural Gas | 26 |
| Odessa Natural Gasoline Co. | | | |
| Odessa, Ector | 1961 | Natural Gas | 13 |
| J. L. Parker Co. | | | |
| Penwell, Ector | Before 1962 | Natural Gas | 30 |
| Phillips Petroleum Co. | | | |
| Goldsmith, Ector | Before 1961 | Natural Gas | 75 |
| Elcor Chemical Corp. | | | |
| Midland, Midland | 1958 | Natural Gas | 1 Standby |
| Amoco Production Co. | | | |
| Midland Farms, Andrews | 1956 | Natural Gas | 11 |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| TEXAS | | | |
| Amoco Production Co. | | | |
| South Fullerton, Andrews | 1968 | Natural Gas | 6 |
| J. L. Parker Co. | | | |
| Andrews, Andrews | Before 1961 | Natural Gas | 15 |
| Sulpetro Corp. | | | |
| Big Spring, Howard | 1966 | Refinery | 10 |
| Amoco Production Co. | | | |
| Sundown, Hockley | 1951 | Natural Gas | 48 |
| Cities Service Oil Co. | | | |
| Welch, Dawson | 1970 | Natural Gas | 4 |
| Cities Service Oil Co. | | | |
| Seminole, Gaines | Before 1961 | Natural Gas | 28 |
| Cities Service Oil Co. | | | |
| Lehman, Cochran | Before 1972 | Natural Gas | 4 |
| Cities Service Oil Co. | | | |
| Lehman, Cochran | 1962 | Natural Gas | 9 |
| Diamond Shamrock Corp. | | | |
| Sunray, Moore | 1951 | Natural Gas & Refinery | 30 |
| Texas Sulfur Products Inc. | | | |
| Dumas, Moore | 1966 | Natural Gas | 13 |
| Phillips Petroleum Co. | | | |
| Borger, Hutchinson | 1968 | Refinery | 33 |
| Trans-Jeff Chemical Corp. | | | |
| Tilden, McMullen | Before 1962 | Natural Gas | 20 |
| Expansion | 1962 | Natural Gas | +80 |
| Atlantic Richfield Co. | | | |
| Fashing, Atascosa | Before 1961 | Natural Gas | 10 |
| Elcor Chemical Corp. | | | |
| Fashing, Atascosa | 1960 | Natural Gas | 55 |
| Humble Oil & Refining Co. | | | |
| Jourdanton, Atascosa | 1967 | Natural Gas | 22 |
| Warren Petroleum Corp. | | | |
| Fashing, Atascosa | Before 1962 | Natural Gas | 45 |
| Shell Oil Co. | | | |
| Person, Karnes | 1962 | Natural Gas | 12 |
| Expansion | 1965 | Natural Gas | +23 |
| Coastal States Gas Producing Co. | | | |
| Kenedy, Karnes | 1968 | Natural Gas | 9 |
| Coastal States Petrochemical Co. | | | |
| Corpus Christi, Nueces | 1972 | Refinery | 85 |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| TEXAS | | | |
| Phillips Petroleum Co. | | | |
| Sweeny, Brazoria | 1967 | Refinery | 25 |
| Atlantic Richfield Co. | | | |
| Houston, Harris | 1960 | Refinery | 30 |
| Expansion | 1970 | Refinery | Not Reported |
| Signal Oil & Gas Co. | | | |
| Houston, Harris | 1963 | Refinery | 40 |
| Expansion | 1967 | Refinery | 10 |
| Shell Oil Co. | | | |
| Deer Park, Harris | Before 1962 | Refinery | 50 |
| Expansion | 1966 | Refinery | +50 |
| Expansion | 1970 | Refinery | +300 Two Trains |
| Stauffer Chemical Co. | | | |
| Baytown, Harris | 1953 | | 70 |
| Expansion | 1962 | Refinery | +121 |
| Atlantic Richfield Co. | | | |
| Port Arthur, Jefferson | 1961 | Refinery | 38 |
| Expansion | 1967 | Refinery | +35 |
| BP Oil Corp. | | | |
| Port Arthur, Jefferson | 1972 | Refinery | 35 |
| Gulf Oil Corp. | | | |
| Port Arthur, Jefferson | Before 1961 | Refinery | 75 |
| Expansion | 1962 | Refinery | +75 |
| Mobil Oil Corp. | | | |
| Beaumont, Jefferson | Before 1962 | Refinery | 50 |
| Olin Corp. | | | |
| Beaumont, Jefferson | 1959 | Natural Gas | 50 Standby |
| Amoco Production Co. | | | |
| Edgewood, Van Zandt | 1964 | Natural Gas | 576 |
| Cities Service Oil Co. | | | |
| Myrtle Springs, Van Zandt | 1968 | Natural Gas | 270 |
| American Petrofina | | | |
| Mount Pleasant, Titus | 1969 | Refinery | 16 |
| Amoco Production Co. | | | |
| West Yantis, Wood | 1963 | Natural Gas | 80 |
| Elcor Chemical Corp. | | | |
| Queen City, Bowie | 1966 | Natural Gas | 30 Dismantled |
| Getty Oil Co. | | | |
| Cayuga, Anderson | Before 1972 | Natural Gas | 130 |
| Getty Oil Co. | | | |
| Winnsboro, Franklin | 1969 | Natural Gas | 224 |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| TEXAS | | | |
| Shell Oil Co. | | | |
| Bryan's Mill, Cass | 1962 | Natural Gas | 200 |
| Texaco, Inc. | | | |
| Dunbar, Rains | 1966 | Natural Gas | 70 |
| Warren Petroleum Corp. | | | |
| Sulphur Springs, Hopkins | 1965 | Natural Gas | 89 |
| UTAH | | | |
| Chevron Oil Co. | | | |
| Salt Lake City | 1972 | Refinery | 12 |
| Union Oil Co. of California | | | |
| Lisbon, San Juan | 1967 | Natural Gas | 10 |
| VIRGINIA | | | |
| American Oil Co. | | | |
| Yorktown, York | 1957 | Refinery | 50 |
| WASHINGTON | | | |
| Rayonier, Inc. | | | |
| Hoquiam, Grays Harbor | 1962 | Chemical | 20 |
| WEST VIRGINIA | | | |
| PPG Industries, Inc. | | | |
| South Charleston, Kanawha | 1960 | Chemical | 27 |
| WISCONSIN | | | |
| Murphy Oil Corp. | | | |
| Superior, Douglas | 1972 | Refinery | 15 |
| WYOMING | | | |
| Amoco Production Co. | | | |
| Riverton, Fremont | 1965 | Natural Gas | 70 |
| Atlantic Richfield Co. | | | |
| Riverton, Fremont | 1963 | Natural Gas | 12 |
| Western Nuclear, Inc. | | | |
| Riverton, Fremont | 1968 | Natural Gas | 5 |
| Amoco Production Co. | | | |
| Powell, Park | 1949 | Natural Gas | 110 |
| Chem-Gas Products Co. | | | |
| Powell, Park | 1961 | Natural Gas | 14 |
| Husky Oil Co. | | | |
| Ralston, Park | 1964 | Natural Gas | 32 |
| Expansion | 1966 | Natural Gas | +15 |
| Amoco Production Co. | | | |
| Worland, Washakie | 1958 | Natural Gas | 22 Standby |

| State/Company/City, County | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| WYOMING | | | |
| Texas Gulf Sulfur Co. | | | |
| Worland, Washakie | 1950 | Natural Gas | 400 Standby |
| Jefferson Lake Sulfur Co. | | | |
| Manderson, Big Horn | Before 1959 | Natural Gas | 113 Standby |
| Atlantic Richfield Co. | | | |
| Sinclair, Carbon | Before 1962 | Natural Gas | 26 |
| Signal Oil & Gas Co. | | | |
| Nieber Dome | Before 1962 | Natural Gas | 50 |
| Texas-Seaboard Inc. | | | |
| Silvertip | 1957 | Natural Gas | 50 Standby |

# APPENDIX D - CLAUS SULFUR PLANTS IN CANADA

| Province/Company/City | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| ALBERTA | | | |
| Amerada Hess Corporation | | | |
| Calgary | 1970 | Natural Gas | 400 |
| Amerada Hess Corporation | | | |
| Olds | 1964 | Natural Gas | 153 |
| Expansion | 1967 | Natural Gas | +33 |
| Amoco Canada Petroleum Company Ltd. | | | |
| Bigstone | 1968 | Natural Gas | 370 |
| Amoco Canada Petroleum Company Ltd. | | | |
| East Crossfield | 1968 | Natural Gas | 1660 |
| Amoco & Texas Gulf Sulfur Co. | | | |
| West Whitecourt | 1962 | Natural Gas | 700 |
| Expansion | 1965 | Natural Gas | +525 |
| Expansion | 1968 | Natural Gas | +650 |
| Aquitaine Company of Canada Ltd. | | | |
| Rainbow Lake | 1968 | Natural Gas | 75 |
| Expansion | 1973 | Natural Gas | +75 |
| Aquitaine Company of Canada Ltd. | | | |
| Rocky Mountain House | 1972 | Natural Gas | 2032 |
| Atlantic Richfield Canada Ltd. | | | |
| Gold Creek | 1971 | Natural Gas | 106 |
| Canadian Delhi Oil Ltd. | | | |
| Minnehik | 1967 | Natural Gas | 26 |
| Expansion | 1972 | Natural Gas | +9 |
| Canadian Fina Oil Ltd. | | | |
| Cochrane | 1961 | Natural Gas | 106 |
| Canadian Industrial Gas & Oil Ltd. | | | |
| Kessler | 1962 | Natural Gas | 10 |
| Canadian Superior Oil Ltd. | | | |
| Harmattan | 1966 | Natural Gas | 817 |
| Canadian Superior Oil Ltd. | | | |
| South Lone Pine Creek | 1972 | Natural Gas | 133 |
| Chevron Standard Limited | | | |
| Fox Creek | 1972 | Natural Gas | 3065 |
| Chevron Standard Limited | | | |
| Nevis | Before 1972 | Natural Gas | 155 |
| Great Canadian Oil Sands Ltd. | | | |
| McMurray | 1967 | Refinery | 350 |
| Gulf Oil Canada Limited | | | |
| Braeburn | 1965 | Natural Gas | 3 |

| Province/Company/City | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| **ALBERTA** | | | |
| Gulf Oil Canada Limited | | | |
| Calgary | 1967 | Refinery | 50 |
| Gulf Oil Canada Limited | | | |
| Nevis | 1960 | Natural Gas | 76 |
| Expansion | 1966 | Natural Gas | +50 |
| Expansion | 1970 | Natural Gas | +50 |
| Gulf Oil Canada Limited | | | |
| Pincher Creek | 1957 | Natural Gas | 225 |
| Expansion | 1962 | Natural Gas | +450 |
| Gulf Oil Canada Limited | | | |
| Rimbey | 1961 | Natural Gas | 246 |
| Expansion | 1965 | Natural Gas | +120 |
| Gulf Oil Canada Limited | | | |
| Strachan | 1972 | Natural Gas | 830 |
| Gulf Oil Canada Limited | | | |
| Turner Valley | 1952 | Natural Gas | 35 |
| Home Oil Co., Ltd. | | | |
| Carstairs | 1960 | Natural Gas | 42 |
| Expansion | 1967 | Natural Gas | +8 |
| Expansion | 1973 | Natural Gas | +52 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Brazeau River | 1968 | Natural Gas | 21 |
| Expansion | 1969 | Natural Gas | +29 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Caroline | 1968 | Natural Gas | 16 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Carstairs | 1967 | Natural Gas | 102 |
| Expansion | 1969 | Natural Gas | +72 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Edson | 1965 | Natural Gas | 225 |
| Expansion | 1971 | Natural Gas | +64 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Fox Creek | 1970 | Natural Gas | 1044 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Fox Creek | 1970 | Natural Gas | 1030 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Sturgeon Lake | 1970 | Natural Gas | 50 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Sundre | 1968 | Natural Gas | 18 |
| Hudson's Bay Oil & Gas Co. Ltd. | | | |
| Sylvan Lake | 1969 | Natural Gas | 11 |

| Province/Company/City | Year Sulfur Production Started | Acid Gas Source | Daily Sulfur Capacity Long Tons |
|---|---|---|---|
| ALBERTA | | | |
| Imperial Oil Ltd. | | | |
| Quirk Creek | 1971 | Natural Gas | 200 |
| Imperial Oil Ltd. | | | |
| Redwater | 1956 | Natural Gas | 9 |
| Jefferson Lake Petrochemicals of Canada Ltd. | | | |
| Balzac | 1961 | Natural Gas | 870 |
| Expansion | 1967 | Natural Gas | +1100 |
| Jefferson Lake Petrochemicals of Canada Ltd. | | | |
| Coleman | 1961 | Natural Gas | 377 |
| Mobil Oil Canada, Ltd. | | | |
| Wimborne | 1964 | Natural Gas | 335 |
| Shell Canada Ltd. | | | |
| Burnt Timber | 1971 | Natural Gas | 120 |
| Shell Canada Ltd. | | | |
| Innisfail | 1960 | Natural Gas | 100 |
| Shell Canada Ltd. | | | |
| Jumping Pound | 1951 | Natural Gas | 90 |
| Expansion | 1971 | Natural Gas | +240 |
| Shell Canada Ltd. | | | |
| Jumping Pound | 1967 | Natural Gas | 140 |
| Shell Canada Ltd. | | | |
| Simonette | 1971 | Natural Gas | 90 |
| Shell Canada Ltd. | | | |
| Waterton | 1962 | Natural Gas | 1200 |
| Expansion | 1967 | Natural Gas | +450 |
| Shell Canada Ltd. | | | |
| Waterton | 1972 | Natural Gas | 1230 |
| Tenneco Oil & Minerals, Ltd. | | | |
| Nordegg River | Before 1972 | Natural Gas | 40 |
| Texas Gulf Sulfur Co. | | | |
| Okotoks | 1959 | Natural Gas | 380 |
| Texas Gulf Sulfur Co. | | | |
| Wild Horse Creek | 1966 | Natural Gas | 30 |
| Expansion | 1968 | Natural Gas | +620 |
| BRITISH COLUMBIA | | | |
| Gulf Oil Canada Limited | | | |
| Port Moody | 1972 | Refinery | 25 |
| Jefferson Lake Petrochemicals of Canada Ltd. | | | |
| Taylor | 1957 | Natural Gas | 325 |
| Shell Canada Ltd. | | | |
| North Burnaby | 1968 | Refinery | 15 |

| Province/Company/City | Year Sulfur Production Started | Acid Gas Source | Daily Suflur Capacity Long Tons |
|---|---|---|---|
| MANITOBA | | | |
| Imperial Oil Ltd. | | | |
| Winnipeg | 1966 | Refinery | 14 |
| NEW BRUNSWICK | | | |
| Irving Refining, Ltd. | | | |
| St. John | 1962 | Refinery | 28 |
| NEWFOUNDLAND | | | |
| Newfoundland Refining Co., Ltd. | | | |
| Come By Chance | 1973 | Refinery | 25 |
| NOVA SCOTIA | | | |
| Imperial Oil Ltd. | | | |
| Dartmouth | 1966 | Refinery | 35 |
| Imperial Oil Ltd. | | | |
| Halifax | 1966 | Refinery | 25 |
| QUEBEC | | | |
| Imperial Oil Ltd. | | | |
| Montreal | 1965 | Refinery | 35 |
| Laurentide Chemicals and Sulfur Ltd. | | | |
| Montreal | 1958 | Refinery | 100 |
| Expansion | Before 1972 | Refinery | +200 |
| ONTARIO | | | |
| Allied Chemical Corp. | | | |
| Sudbury | Before 1972 | Smelter | 275 |
| Cornwall Chemicals Ltd. | | | |
| Cornwall | 1965 | Refinery | 75 |
| Gulf Oil Canada Limited | | | |
| Clarkson | 1963 | Refinery | 40 |
| Imperial Oil Ltd. | | | |
| Sarnia | 1964 | Refinery | 25 |
| Expansion | 1968 | Refinery | +60 |
| Shell Canada Ltd. | | | |
| Oakville | 1963 | Refinery | 46 |
| Shell Canada Ltd. | | | |
| Sarnia | 1966 | Refinery | 35 |
| Sun Oil Co. Ltd. | | | |
| Sarnia | 1970 | Refinery | 13 |
| SASKATCHEWAN | | | |
| Dome Petroleum Limited | | | |
| Steelman | 1965 | Natural Gas | 15 |

# APPENDIX E - AMOCO PRODUCTION COMPANY INFORMATION

February 15, 1972

Dr. Paul F. Hawley
Patent Director
Amoco Production Company
Box 591
Tulsa, Oklahoma 74102

Subject: Claus Sulfur Plant
Performance

Dear Dr. Hawley:

Several of the methods being considered for abatement of sulfur emissions to the atmosphere include Claus sulfur units. The Environmental Protection Agency Office of Air Programs has engaged Processes Research, Inc., to study the efficacy of Claus sulfur plants in pollution abatement (Contract No. 68-02-0242).

We understand that your company operates Claus units recovering sulfur which would otherwise be emitted to the atmosphere. Please let us have available information regarding the performance of these units, as follows. The Office of Air Programs interest is in developing pollution control methods and the requested information is for use in these efforts.

1. Location, daily sulfur capacity, days of operation annually and annual sulfur production.
2. Claus process variation used: straight through, split flow, direct oxidation, sulfur recycle, etc.
3. Number of catalytic stages and method of reheating process vapor.
4. Source, quantity and composition of acid gas feed.
5. Quantity and composition of tail gas.
6. Incineration or other tail gas treatment.

7. Frequency of catalyst change and maintenance.

8. Operator attendance and trouble.

9. Consumption and generation of fuel, water, power and steam.

If some of this information is available for one or more of your Claus units, please let us know when we may expect to receive it. We thank you for your cooperation.

Very truly yours,

PROCESSES RESEARCH, INC.

W. D. Beers
Project Manager

WDB:jd

cc: G. S. Haselberger
M. R. Jester
P. W. Spaite

**Amoco Production Company**
Amoco Building
P.O. Box 591
Tulsa, Oklahoma 74102
Producing Department

M. S. Kraemer
Chief Engineer

8 AM 9 26
[illegible] RESEARCH INC.

May 4, 1972

Mr. W. D. Beers
Project Manager
Processes Research Inc.
2912 Vernon Place
Cincinnati, Ohio 54210

Dear Mr. Beers:

Subject: Sulfur Plant Performance

Your letter of February 15, 1972 to Dr. Paul F. Hawley has been referred to me for a reply. You have indicated that you are making a study of Claus sulfur plant efficacy in pollution abatement under contract with the Environmental Protection Agency. For your study a summary of data concerning the plants operated by Amoco Production Company is attached. However, the information will soon be out of date for many of the plants since studies are underway to modify them to meet recently revised state emission regulations.

All these plants recover sulfur from hydrogen sulfide which has been extracted from natural gas to reduce emission of sulfur to the atmosphere. The acid gas feed normally contains hydrogen sulfide, carbon dioxide, hydrocarbons and water. The plant tail gas before incineration is predominately nitrogen, carbon dioxide and water vapor with small quantities of hydrogen sulfide (0.5-1.5 mol%), sulfur dioxide (0.25-0.75 mol%), carbonyl sulfide (0.01-0.04 mol%), carbon disulfide (0.01-0.05 mol%), plus fractions of a percent of hydrogen and carbon monoxide and elemental sulfur (vapor and entrained). Incineration converts the sulfur compounds to sulfur dioxide.

These plants have low maintenance requirements and low operating costs which combined amount to about 8 to 15% of capital investment per year. Catalyst life is normally about ten years. Changes are otherwise made only in the event of plant upsets which result in damage to the catalyst.

Operator attendance requirements vary depending upon the design of the plant and the amount of other duties assigned. Full time operator attendance is not required.

For a more detailed discussion of sulfur plants, please refer to the attached copy of "Why Recover Sulfur from $H_2S$."

Yours truly,

Attachment

cc - Dr. P. F. Hawley

SHEET 1 OF 3

## AMOCO PRODUCTION COMPANY

Sulfur Recovery Plants

**(As of April 1972 - Plant Revisions now being studied for compliance with new state air conservation regulations as soon as approved by EPA)**

| | Beaver Creek | Elk Basin | Empire Abo |
|---|---|---|---|
| LOCATION: County | Fremont | Park | Eddy |
| State | Wyoming | Wyoming | N. Mex. |
| Daily Sulfur Capacity, LTD | 70 | 110 | 26 |
| Days of Operation, Annually | 365 less downtime for required maintenance. (Usually about 360 days/years). | | |
| Annual Sulfur Production (1971) LT | 14,447 | 12,860 | 9,586 |
| Process, Claus | st. thru | split flow | st. thru |
| Number of Catalytic stages | 2 | 2 | 2 |
| Reheat Method | bypass | inline htr. | bypass |
| Acid Gas Feed | | | |
| Source | Natural Gas | Natural Gas | Natural Gas |
| Quantity, MMCFD | 1.2 | 2.0 | 1.1 |
| Composition, mol %$H_2S$ | 88 | 60 | 65 |
| Plant Tail Gas Quantity MMCFD | 3.3 | 3.7 | 2.68 |
| Tail Gas Treatment | None | None | None |
| Catalyst Change Frequency | - only in the event of catalyst damage - | | |
| Utilities | | | |
| Cooling Water MMBtu/hr. | -- | -- | -- |
| Steam #/hr.,consumed* | | | |
| " " " generated | 10,700 | 10,900 | 7,000 |
| Fuel gas MMCFD | | | |
| Instrument air (negligible) | | | |
| Electrical KW* | | | |

*(Approx. 2 HP/LT/D for blower steam or electrical)

SHEET 2 OF 3

# AMOCO PRODUCTION COMPANY

## Sulfur Recovery Plants

(As of April 1972 - Plant Revisions now being studied for compliance with new state air conservation regulations as soon as approved by EPA)

| | Edgewood | Midland Farms | North Cowden |
|---|---|---|---|
| LOCATION: County | Van Zandt | Andrews | Ector |
| State | Texas | Texas | Texas |
| Daily Sulfur Capacity, LTD | 576 | 11 | 26 |
| Days of Operation, Annually | 365 less downtime for required maintenance. (Usually about 360 days/years). | | |
| Annual Sulfur Production (1971) LT | 120,959 | 3,018 | 9,352 |
| Process, Claus | st. thru | st. thru | st. thru |
| Number of Catalytic stages | 2 | 2 | 2 |
| Reheat Method | bypass exchanger | bypass | inline htr. |
| Acid Gas Feed | | | |
| Source | Natural Gas | Natural Gas | Natural Gas |
| Quantity, MMCFD | 10.2 | 0.5 | 2.1 |
| Composition, mol $\%H_2S$ | 86 | 52 | 61 |
| Plant Tail Gas Quantity MMCFD | 29.4 | .93 | 2.8 |
| Tail Gas Treatment | Incineration | None | None |
| Catalyst Change Frequency | - Only in the event of catalyst damage - | | |
| Utilities | | | |
| Cooling Water MMBtu/hr. | -- | -- | -- |
| Steam #/hr., consumed* | | 0 | |
| " " " generated | 88,000 | 2,600 | 7,700 |
| Fuel gas MMCFD | 500 | | |
| Instrument air (negligible) | | | |
| Electrical KW* | | | |

*(Approx. 2 HP/LT/D for blower steam or electrical)

SHEET 3 OF 3

## AMOCO PRODUCTION COMPANY

Sulfur Recovery Plants

**(As of April 1972 - Plant Revisions now being studied for compliance with new state air conservation regulations as soon as approved by EPA)**

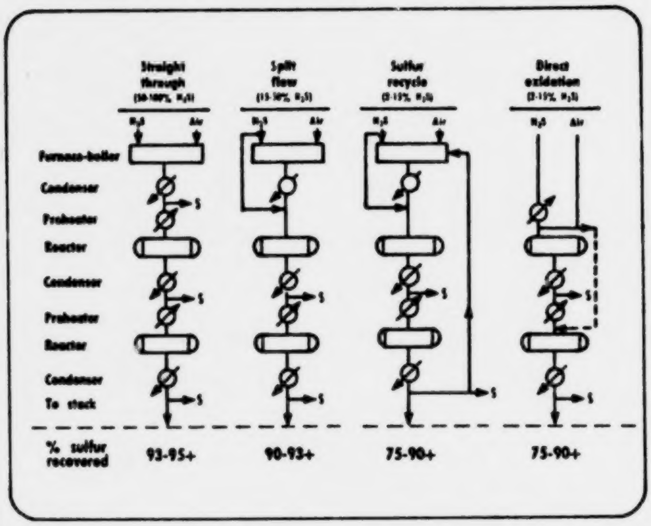
| | Slaughter | South Fullerton | West Yantis |
|---|---|---|---|
| LOCATION: County | Hockley | Andrews | Wood |
| State | Texas | Texas | Texas |
| Daily Sulfur Capacity, LTD | 48 | 6 | 80 |
| Days of Operation, Annually | 365 less downtime for required maintenance. (Usually about 360 days/years). | | |
| Annual Sulfur Production (1971) LT | 13,033 | 1,406 | 9,324 |
| Process, Claus | split flow | st. thru | st. thru |
| Number of Catalytic stages | 2 | 2 | 2 |
| Reheat Method | bypass | bypass | bypass |
| Acid Gas Feed | | | |
| Source | Natural Gas | Natural Gas | Natural Gas |
| Quantity, MMCFD | 6.3 | .4 | 1.75 |
| Composition, mol %$H_2S$ | 23 | 42 | 41 |
| Plant Tail Gas Quantity MMCFD | 7.5 | 0.5 | 3.3 |
| Tail Gas Treatment | None | None | Incineration |
| Catalyst Change Frequency | - Only in the event of catalyst damage - | | |
| Utilities | | | |
| Cooling Water MMBtu/hr. | 2.4 | -- | -- |
| Steam #/hr., consumed* | | 0 | |
| " " " generated | 10,400 | 1100 | 7,900 |
| Fuel gas MMCFD | | | 35 |
| Instrument air (negligible) | | | |
| Electrical KW* | | | |

*(Approx. 2 HP/LT/D for blower steam or electrical)

# Why recover sulfur from $H_2S$?

Fig. 1

Processes for sulfur recovery from $H_2S$



H. Grekel
J. W. Palm
and
J. W. Kilmer
Pan American Petroleum Corp.
Tulsa, Okla.

**Interest** in the recovery of sulfur from hydrogen sulfide has never been higher. Here's why:

- World demand for sulfur is high and continuing to increase.
- New reserves of natural gas containing hydrogen sulfide have been discovered.
- A number of city, state, and federal air-quality-control laws have been enacted.
- Sulfur prices are high, and should go higher.

So, several incentives, both economic and legal, exist for increasing sulfur recovery from sour gas. It would be expected that recent plant construction would show an increase over that recorded previously.

A comparison reveals some interesting facts.

By the end of 1968, there will have been constructed 132 plants of this type in the United States, plus 29 expansions of existing plants, many of which are really new parallel plants.

Of these, 78 were built in 1961 or before, and 83 since. At the end of 1968, as in 1961, 58% will be in refineries (or chemical plants) and the remainder in natural-gas processing plants. Table 1 shows a list of all U.S. sulfur plants.

The largest plant before 1961 was Texas Gulf Sulphur's Worland, Wyo., plant which began operating in 1950 and shut down in 1967. It had 400 long tons/day (LT/D) capacity. The largest U.S. plant today (580 LT/D) is Pan American Petroleum's Edgewood, Tex., plant completed in 1964.

Pan American Petroleum also operates the largest number of plants, nine, closely followed by National Sulfur (Elcor Chemical Co.) with six. Pan American, National Sulfur and other licensees of Pan American's patents and know-how account for 49% of the sulfur recovery capacity built in the United States since 1961.

The average per-plant capacity of the U.S. operating plants and expansions constructed has remained substantially unchanged in recent years (in 1961 and before, 54 LT/D in natural gas plants and 62 LT/D in refineries; since 1961, 54 LT/D in natural gas plants and 52 LT/D in refineries).

In 1961, only 13% of the plants in operation were of greater than 100 LT/D capacity and at year-end 1968, only 17%. The overall percentage of plants with 25 LT/D or smaller capacity was 35% in 1961 and will be 33% at the end of 1968.

The capacity of U.S. plants to recover sulfur from hydrogen sulfide increased 40% from 1,659,000 long tons/year (LT/YR) at the end of 1961 to 2,737,000 LT/YR at end of 1967.

At year-end 1968, the capacity of 3,036,000 LT/YR will be nearly double the 1961 recovered sulfur capacity. The actual production of recovered sulfur in 1961 of 858,000 LT and 1967 of 1,244,000 LT represented only 52 and 45%, respectively, of the year-end sulfur recovery capacity.

By contrast, the Canadian plant capacity will have more than quadrupled from 1961 to 1968. Production in 1961 of 486,000 LT was 43% of the 1,140,000 LT/YR capacity and in 1967 the 2,200,000 LT production was 51% of the year-end 4,300,000 LT/YR plant capacity. At the end of 1968, Canadian recovered sulfur plant capacity will be 5,034,000 LT/YR.

The Canadian sulfur plant size and balance between natural gas and refineries are much different from the pattern in the United States. Table 2 is a list of Canadian sulfur plants. In 1961, the 14 sulfur plants based on natural gas averaged 214 LT/D.

The largest plant was the Petrogas Balzac, Alta., plant at 870 LT/D. It is still the largest, having expanded in 1967 to 1,970 LT/D.

In Canada, 45% of the plants are over 100 LT/D and only 20% under 25 LT/D. There will have been built 50 plants plus 10 expansions by the end of 1968.

The average capacity of Canadian plants at the end of 1968 will have increased somewhat, averaging 357 LT/D for the 36 natural gas-based and 67 LT/D for the 14 refinery-based sulfur plants.

The average size in refineries is influenced greatly by the 350 LT/D Great Canadian Oil Sand sulfur plant added in 1967.

*(Continued on p. 93)*

Fig. 2

Sulfur-recovery plant investment

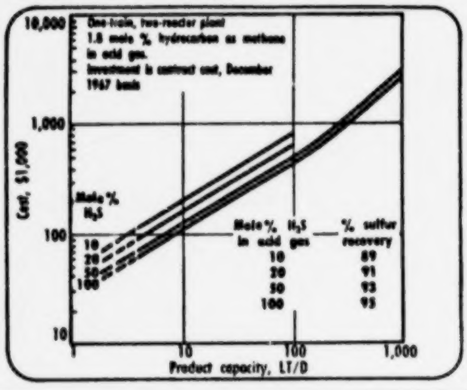
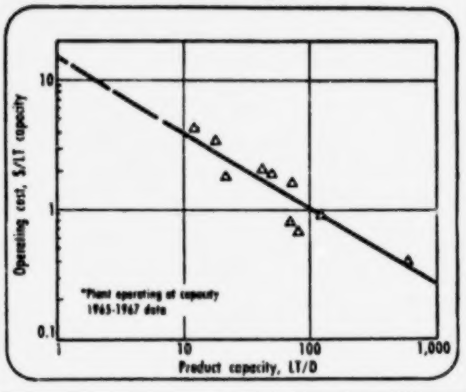


Fig. 3

Sulfur-plant operating cost



There will be in Alberta at the close of 1968 four plants of over 1,000 LT/D capacity.

The fourth, at 1,480 LT/D capacity, started up in February 1968, is now operated at East Crossfield by Pan American Petroleum Corp.

Historically, sulfur recovered from $H_2S$ has been a by-product whose economics have been dependent only on the last step of the recovery process. The removal of the $H_2S$ from natural gas or refinery gas was justified by the value of the sweet fuel.

Even at sulfur prices as low as $17/LT, the sulfur recovery plant could be justified economically down to 4 LT/D.

At today's Oil, Paint and Drug Reporter sulfur price posting of $42/LT (fob Gulf Coast for bright sulfur), even small by-product sulfur plants can be justified.

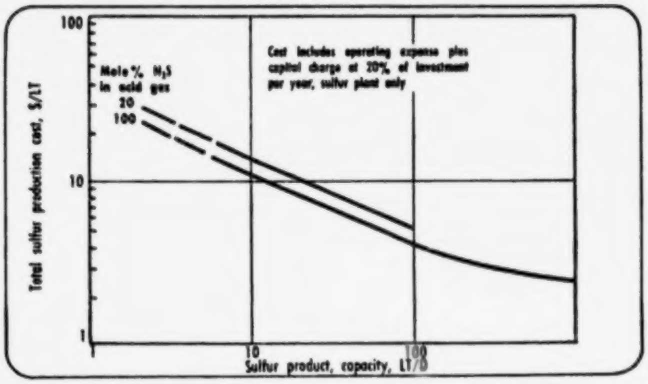
In contrast, high sulfur prices have made attractive the construction of several large Canadian sulfur plants where the residue gas value would not support the sweetening plant costs. Value of sulfur production may be 90% of the total income—enough to justify the entire project.

The need and desirability of recovering sulfur have led to development of revised methods of recovering sulfur from more dilute streams of hydrogen sulfide. Economic designs have been developed for recovery of sulfur from acid gas containing as little as 2 vol % $H_2S$.

**Straight-through process.** If the hydrogen sulfide concentration of the feed gas is high enough that stable combustion of the total stream is obtainable, then the total stream is fed to the burner in a furnace or boiler as shown for the straight-through process in Fig. 1. Air is fed to the burner to provide oxygen for the overall reaction: $H_2S + \frac{1}{2} O_2 \rightarrow S + H_2O$

Fig. 4

Total sulfur-recovery cost from acid gas



In addition, air is provided to react with hydrocarbons in the acid-gas feed. Sulfur is produced in the flame, but sulfur dioxide is also formed, and some $H_2S$ is unreacted.

The gases leaving the furnace are cooled, usually condensing sulfur from the gas, which is then preheated and fed to a catalytic reactor containing bauxite catalyst where the Claus reaction occurs.

$$2H_2S + SO_2 \rightarrow 3S + 2H_2O$$

The gas then passes to a condenser to remove liquid sulfur. Usually a second reactor and condenser (and sometimes a third) are used to get higher yields. Typical recovery levels for the straight-through process and other processes are shown in Fig. 1.

**Split-flow process.** If the hydrogen sulfide concentration of the acid gas is so low that the gas will not burn using the straight-through process, then as much as two-thirds of the gas may be bypassed around the furnace as shown for the split flow process in Fig. 1.

In this case, most of the hydrogen sulfide fed to the furnace is oxidized to sulfur dioxide and little or no sulfur is produced in the furnace.

The hot gas from the furnace is

cooled and blended with the bypass gas to obtain the desired preheat temperature for the reactor, where the hydrogen sulfide from the bypass gas reacts with the sulfur dioxide from the furnace by the Claus reaction over bauxite catalyst to produce sulfur.

The reactor and condenser train are similar to that of the straight-through process. Preheating of the feed gas may be used to permit processing by this method of feed gas containing less than 15 mole % $H_2S$.

These two methods can be used for handling acid gas which is too lean to achieve stable combustion in the split flow process:

1. Sulfur recycle process
2. Direct oxidation process

**Sulfur-recycle process.** In the sulfur-recycle process, product sulfur is recycled to the furnace and burned with air to produce sulfur dioxide. Some of the feed $H_2S$ may also be burned in the furnace to produce sulfur dioxide.

The sulfur dioxide formed in the furnace is fed with acid-gas feed to the Claus reactors as shown in Fig. 1. The reactor-condenser train would again be similar to the straight-through process.

**Direct-oxidation process.** In the direct-oxidation process, the acid-gas feed is preheated, mixed with air, and passed directly to a catalytic reactor, as shown in Fig. 1. The oxygen reacts with the hydrogen sulfide to produce sulfur dioxide and sulfur.

Most direct oxidation plants require two or three reactors. Further details concerning this process have been published previously.[1,2]

**Limitations of processes.** The straight-through and split-flow processes are limited by process considerations to those gases which contain a high enough concentration of $H_2S$ to obtain stable combustion.

The sulfur-recycle process and direct-oxidation process have practically no lower limit on the hydrogen sulfide

## U.S. sulfur-recovery plants from $H_2S$

| Operating company | Plant location | Year started up *or earlier (S-shutdown, yr) | Feed Source Chemical Refinery Natural Gas | Cap. LT/D |
|---|---|---|---|---|
| Allied Chemical | Elizabeth, N.J. | 1958 (S, 1967) | R | 30 |
| | El Segundo, Calif. | 1959 (S, 1967) | R | 175 |
| | General Chem. Div. | 1964 | R | 100 |
| | Richmond. Calif. | 1961* | R | 100 |
| | Expansion | 1968 | R | + 100 |
| Amarillo Oil | Goldsmith, Tex. | 1967 | N | 7 |
| American Cyanamid | Bound Brook, N.J. | 1967 | R-C | 12 |
| American Oil | Whiting, Ind. | 1952 | R | 64 |
| | Expansion | 1964 | R | +40 |
| | Yorktown, Va. | 1957 | R | 50 |
| Anlin Co. of Ill. | Wood River, Ill. | 1960 | R | 150 |
| Anlin Co. of N.J. | Perth Amboy, N.J. | 1957 | R | 35 |
| | Expansion | 1962 | R | +15 |
| Arkla Chem. Corp. | Magnolia, Ark. | 1961* | N | 19 |
| | Expansion | 1962 | N | +11 |
| Atlantic-Richfield, Arco Chemical Co. Div. | Philadelphia, Pa. | 1964 | R | 38 |
| | Port Arthur, Tex. | 1961 | R | 38 |
| | Riverton, Wyo. | 1963 | N | 12 |
| | Watson, Calif. | 1967 | R | 65 |
| Cities Service | Myrtle Springs, Tex. | 1968 | N | 228 |
| | Milnesand, N.M. | 1967 | N | 20 |
| | Seminole, Tex. | 1960* | N | 28 |
| Climax Chemical | Oil Center, N.M. | 1962 | N | 18 |
| Coastal States Gas Production Co. | Kennedy, Tex. | 1968 | N | 9 |
| Continental Oil | Denver, Colo. | 1968 | R | 18 |
| | Paramount, Calif. | 1966 | R | 9 |
| Diamond-Shamrock | Sunray, Tex. | 1951 | N-R | 30 |
| El Paso Natural Gas | Eunice, N.M. | 1960* | R | 30 |
| Farmer's Union Central Exchange | Laurel, Mont. | | R | 28 |
| Farmland Industries, Inc. | Coffeyville, Kan. | 1968 | R | 6 |
| Fletcher Oil | Wilmington, Calif. | 1961*(S, 1967) | R | 7 |
| Freeport Sulfur | Westville, N.J. | 1960* | R | 30 |
| Getty Oil | Delaware City, Del. | 1956 | R | 375 |
| | Winnsboro, Tex. | 1969 | N | 224 |
| Golden Eagle Refinery | Torrance, Calif. | 1959 (S, 1967) | R | 4 |
| Great Northern Oil | Pine Bend, Minn. | 1955 | R | 60 |
| | Expansion | 1963 | R | +70 |
| Gulf Oil | Philadelphia, Pa. | 1960* | R | 135 |
| | Port Arthur, Tex. | 1960* | R | 75 |
| | Expansion | 1962 | R | +75 |
| | Purvis, Miss. | 1960* | R | 30 |
| | Santa Fe Springs, Calif. | 1960* | R | 8 |
| | Expansion | 1961* | R | 9 |
| | Expansion | 1964 | R | 13 |
| Hess Oil | St. Croix,-Virgin Is. | 1967 | R | 40 |
| Hess Oil & Chemical Corp. | Port Reading, N.J. | 1966* | R | 40 |
| Humble Oil & Refining | Baton Rouge, La. | 1967 | R | 10 |
| | Benicia, Calif. | 1968 | R | 270 |
| | Jourdanton, Tex. | 1967 | N | 22 |
| Husky Oil | Ralston, Wyo. | 1964 | N | 32 |
| | Expansion | 1966 | N | 15 |
| Jefferson Lake Sulphur | Manderson, Wyo. | 1958*(S, 1960) | N | 113 |
| Leonard Refineries, Inc. | Alma, Mich. | 1956 | R | 12 |
| Marathon Oil | Detroit, Mich. | 1960* | R | 27 |
| | Expansion | 1962 | R | +8 |
| | Expansion | 1968 | R | +34 |
| | Indian Basin, N.M. | 1967 | N | 36 |
| | Iraan, Tex. | 1967 | N | 11 |
| Mobil Chemical | Beaumont, Tex. | 1961* | R | 50 |
| | Paulsboro, N.J. | 1960* | R | 95 |
| | Coyanosa, Tex. | 1967 | N | 29 |
| | Woodhaven, Mich. | 1962 | R | 8 |
| | Torrance, Calif. | 1967 | R | 85 |
| Monsanto Chemical | El Dorado, Ark. Lion Oil Div. | 1960* | R | 25 |
| | Avon, Calif. | 1966* | R | 132 |
| Montana Sulphur & Chemical | Billings, Mont. | 1956 | R | 40 |
| | Expansion | 1964 | R | +45 |
| National Sulfur | Midland, Tex. | 1958 (S, 1960) | N | 1 |
| | Fashing, Tex. | 1960 | N | 55 |
| | Lehman, Tex. | 1962 | N | 9 |
| | Canton, Miss. | 1965 | N | 12 |
| | Crane County, Tex. | 1966 | N | 15 |
| | Queen City, Tex. | 1966 | N | 30 |
| | Madill, Okla. | 1967 | N | 8 |
| Northwest Production Corp. | Reagan County, Tex. | 1961* | N | 3 |
| | Expansion | 1962 | N | +5 |
| Northwestern Refining | St. Paul Park, Minn. | 1968 | R | 40 |
| Odessa Natural Gasoline | Odessa, Tex. | 1961 | N | 12 |
| Olin Matheson | Beaumont, Tex | 1959 (S) | N | 50 |
| | McKamie, Ark. | 1944 | N | 100 |
| Pan American Petroleum Corp. | Beaver Creek Riverton, Wyo. | 1965 | N | 70 |
| | Cottonwood Creek Worland Wyo. | 1958 (S, 1964) | N | 22 |
| | Edgewood, Tex. | 1964 | N | 550 |
| | Elk Basin, Powell, Wyo. | 1949 | N | 110 |
| | Empire Abo Artesia, N.M. | 1960 | N | 22 |

content of the gas to be processed from a standpoint of operability.

However, there are economic limits. The lower economic limit on hydrogen sulfide is presently in the neighborhood of 2 to 10 mole % depending on the feed-gas rate and sulfur netback at the plant.

**Contaminants in feed gas.** A typical acid gas from an amine-type natural-gas-sweetening unit which comprises the feed to a sulfur recovery plant contains hydrogen sulfide plus carbon dioxide with about 1 to 2 mole % hydrocarbons.

The $H_2S/CO_2$ ratio depends primarily on the ratio of these components in the feed gas to the sweetening unit since both compounds are absorbed practically quantitatively from the sour-gas stream.

Hydrocarbons in the feed gas to the sulfur plant are usually detrimental for these reasons:

1. In the straight-through process, air must be supplied to the furnace for combustion of the hydrocarbons in the feed gas. The added water and inert gas associated with burning the hydrocarbons increase the size of the sulfur-plant equipment and lower the sulfur recovery.

2. In the split-flow process, hydrocarbons in the feed gas to the furnace have a beneficial effect in helping to maintain flame stability. However, the hydrocarbons in the gas bypassed to the reactor tend to crack over the bauxite catalyst, producing a carbonaceous product which fouls the catalyst and contaminates the product sulfur. The rate of cracking increases with increasing molecular weight of the hydrocarbons.

3. Higher-molecular-weight hydrocarbons in the feed to the sulfur recycle process or the direct-oxidation process also are detrimental because of cracking on the bauxite catalyst.

New gas-sweetening solvents have been developed to obtain higher acid-

Table 1

| Operating company | Plant location | Year started up *or earlier (S-shutdown, yr) | Feed Source Chemical Refinery Natural Gas | Cap. LT/D |
|---|---|---|---|---|
| | Midland Farms Midland, Tex. | 1956 | N | 11 |
| | North Cowden Odessa, Tex. | 1952 | N | 18 |
| | Slaughter Sundown, Tex. | 1951 | N | 48 |
| | South Fullerton Texas | 1968 | N | 6 |
| | West Yantis Tyler, Tex. | 1963 | N | 80 |
| J. L. Parker | Andrews, Tex. | 1960* | N | 15 |
| | Madill, Okla. | 1960* (S) | N | 15 |
| | Penwell, Tex. | 1961* | N | 30 |
| Phillips Petroleum | Borger, Tex. | 1968 | R | 33 |
| | Crane County, Tex. | 1960* | N | 100 |
| | Expansion | 1962 | N | +65 |
| | Goldsmith, Tex. | 1960* | N | 75 |
| | Kansas City, Kan. | 1968 | R | 38 |
| | Sweeney, Tex. | 1967 | R | 25 |
| Pittsburgh Plate Glass | S. Charleston W. Virginia | 1960 | Ch | 27 |
| Powerine Oil | Santa Fe Springs, Calif. | 1967 | R | 20 |
| Rayonier | Hoquiam, Wash. | 1962 | Ch | 25 |
| Republic Steel | Cleveland, Ohio | 1961 | Ch | 6 |
| Sharples, Purvin & Gertz | Powell, Wyo. | 1961 | N | 14 |
| Shell Oil | Bryan's Mill, Tex. | 1962 | N | 180 |
| | Martinez, Calif. | 1966 | R | 100 |
| | Person, Karnes County, Tex. | 1962 | N | 12 |
| | Expansion | 1965 | N | +23 |
| Shell Chemical | Norco, La. | 1965 | R | 40 |
| | Deer Park (Houston) Texas | 1961* | R | 50 |
| | Expansion | 1966 | R | 50 |
| Sid Richardson Carbon & Gasoline | Winkler County, Texas | 1960* | N | 5 |
| Signal Oil & Gas | Houston, Tex. | 1963 | R | 40 |
| | Expansion | 1967 | R | 10 |
| | Nieber Dome, Wyo. | 1961* | N | 50 |
| | Tioga, N.D. | 1953† | R | 72 |
| | Expansion | 1963 (S, 1967) | R | +23 |
| | Expansion | 1967 | R | +150 |
| Sinclair Oil Corporation | Fashing, Tex. | 1960* | N | 10 |
| | Houston, Tex. | 1960* | R | 30 |
| | Marcus Hook, Pa. | 1960* | R | 20 |
| | Expansion | 1962 | R | +32 |
| | Sinclair, Wyo. | 1961* | N | 26 |
| Stauffer Chemical | Baton Rouge, La. | 1950 | R | 30 |
| | Baytown, Tex. | 1953 | R | 70 |
| | Expansion | 1962 | R | 121 |
| | Delaware City, Del. | 1961* | R | 260 |
| | Le Moyne, Ala. | 1961* | R | 127 |
| | Watson, Calif. | 1961* | R | 100 |
| | Expansion | 1961* | R | +20 |
| | Expansion | 1962 | R | +140 |
| | Expansion | 1964 | R | +8 |
| | Expansion | 1967 | R | +132 |
| Sulpetro Corp. | Big Spring, Tex. | 1966 | R | 10 |
| Sun Oil | Toledo, Ohio | 1958 | R | 12 |
| | Marcus Hook, Pa. | 1955 | R | 30 |
| Texas-Seaboard, Inc. | Silver Tip Field, Wyo. | 1957 (S, 1963) | N | 50 |
| Texaco Inc. | Los Angeles, Calif. | 1961* | R | 50 |
| | Lignite, N.D. | 1961 | N | 20 |
| | Dunbar, Tex. | 1966 | N | 70 |
| | St. Charles Parish, La. | 1966 | R | 50 |
| Texas Gulf Sulfur | Worland, Wyo. | 1950 (S, 1967) | N | 400 |
| Texas Sulfur Products, Inc. | Dumas, Tex. | 1966 | N | 13 |
| Trans-Jeff. Chem. Corp. | Tilden, Tex. | 1961* | N | 20 |
| | Expansion | 1962 | N | +80 |
| Union Oil | San Juan County, Utah | 1967 | N | 10 |
| Union Oil Co. of Calif. | Lemont, Ill. | 1960* | R | 20 |
| | Expansion | 1964 | R | +34 |
| | Oleum, Calif. | 1955 | R | 70 |
| | Santa Maria, Calif. | 1954 | R | 55 |
| | Wilmington, Calif. | 1952 | R | 49 |
| | Expansion | 1962 | R | +10 |
| U.S. Steel | Pittsburgh, Pa. | 1966* | Ch | 110 |
| Wanda Petroleum | Kermit, Tex. | 1967 | N | 18 |
| Warren Petroleum | Fashing, Tex. | 1961* | N | 45 |
| | Waddell, Tex. | 1960* | N | 50 |
| | Expansion | 1968 | N | +45 |
| | Sand Hills, Tex. | 1964 | N | 50 |
| | Sulfur Springs, Tex. | 1965 | N | 89 |
| | Tatum, N.M. | 1961 | N | 4 |
| W. R. Grace | Puerto Rico, W.I. | 1966 | R | 2 |
| Western Nuclear, Inc. | Riverton, Wyo. | 1968 | N | 5 |

NOTE: Refinery sulfur plants noted as shut down are assumed to be on standby and not abandoned as the natural gas-based sulfur plants are when the field is shut in. †Derated to 50, 1967.

gas loadings and reduce sweetening costs. These may also increase the pickup of hydrocarbons in the solvent and result in a higher concentration of hydrocarbons in the acid gas.

Therefore, sweetening solvents which reduce the cost of sweetening need to be evaluated also in terms of how much they may add to the sulfur plant investment or operating costs.

Investment costs for sulfur recovery units have shown a definite downward trend as technology has improved. A large part of the reduction in investment cost resulted from using the patented package-plant concept which was developed by Pan American Petroleum Corp. in 1956.

This concept resulted in a cost reduction of about 50% in plant-investment costs at the time it was introduced.

Table 3 compares the actual investment cost of plants built in 1952 with the present cost for an equivalent plant. Today's plant costs (1967) are 62-87% of the actual 1952 plant costs.

When the increase in construction cost is considered, 1967 plant costs are 36-50% of today's cost for the 1952 sulfur-plant design. Therefore, as W. L. Nelson has also reported, improved technology has reduced the contract cost despite a 75% increase in construction costs caused by inflation.[3]

Fig. 2 shows typical investment costs for sulfur recovery plants. These curves represent the contract price for a one-train, two-reactor plant as illustrated by Fig. 1 (straight-through or split-flow). Individual plants may vary plus or minus 20% from these typical curves.

If the feed gas on a dry, hydrocarbon-free basis contains about 20 mole % hydrogen sulfide, the plant cost is about 40% higher than for a 100% $H_2S$ acid-gas feed.

Fig. 3 shows the operating costs for several sulfur-recovery plants which are operated in conjunction with other gas-processing operations.

These costs include operating and maintenance labor and materials and catalyst, but do not include the cost of loading the sulfur, power for the air blower, or fuel and other operating costs for incinerator and dispersal stacks.

The air-blower power will vary with the ratio of hydrocarbon to hydrogen sulfide in the acid gas, type of plant, and the design pressure drop.

The charge for power will also depend on whether electric motor or steam turbine drive is used and what the plant steam balance is. A good average power charge for preliminary evaluation would be $0.35/LT based on 2 hp/daily LT sulfur.

It has been Pan American's experience that even sulfur-recovery plants having capacities of several hundred

## Canadian sulfur-recovery plants from $H_2S$

Table 2

| Operating company | Plant location | Year start-ed up | Refinery or natural gas source | Capacity LT/D |
|---|---|---|---|---|
| Amerada | Olds, Alberta | 1964 | N | 153 |
| | Expansion | 1967 | N | + 33 |
| Banff Oil, Ltd. | Rainbow Lake, Alberta | 1968 | N | 75 |
| British American Oil Co., Ltd. | Pincher Creek, Alberta | 1957 | N | 225 |
| | Expansion | 1962 | N | + 450 |
| | Clarkson, Ontario | 1963 | R | 40 |
| | Braeburn, Alberta | 1965 | N | 3 |
| | Nevis, Alberta | 1960 | N | 76 |
| | Expansion | 1966 | N | + 50 |
| | Rimbey, Alberta | 1961 | N | 246 |
| | Expansion | 1965 | N | + 120 |
| | Turner Valley, Alberta | 1952 | N | 35 |
| | Calgary, Alberta | 1967 | R | 50 |
| Canadian Delhi | Buck Lake, Alberta | 1967 | N | 26 |
| Canadian Fina Oil, Ltd | Wildcat Hills, Alberta | 1961 | N | 106 |
| Canadian Superior | Harmattan, Alberta | 1966 | N | 817 |
| Chevron Standard | Nevis North, Alberta | 1959 | N | 120 |
| | Expansion | 1967 | N | + 30 |
| Cornwall Chemicals | Ontario | 1965 | R | 75 |
| Great Canadian Oil Sands, Ltd. | McMurray, Alberta | 1967 | R | 350 |
| Home Oil | Carstairs, Alberta | 1960 | N | 42 |
| | Expansion | 1967 | N | + 8 |
| Hudson's Bay Oil & Gas | Brazeau River, Alberta | 1968 | N | 21 |
| | Caroline, Alberta | 1968 | N | 16 |
| | Edson, Alberta | 1965 | N | 225 |
| | Lone Pine Creek, Carstairs, Alberta | 1967 | N | 102 |
| | Sundre, Alberta | 1968 | N | 18 |
| Imperial Oil | Dartmouth, Ontario | 1966 | R | 35 |
| | Halifax, Nova Scotia | 1966 | R | 25 |
| | Montreal, Quebec | 1965 | R | 35 |
| | Redwater, Alberta | 1956 | N | 9 |
| | Sarnia, Ontario | 1964 | R | 25 |
| | Expansion | 1968 | R | + 60 |
| | Winnipeg, Manitoba | 1966 | R | 14 |
| Irving Refinery | St. John, New Brunswick | 1961* | R | 28 |
| Laurentide Chemical and Sulphur, Ltd. | Montreal, Quebec | 1958 | R | 100 |
| Mobil Oil Canada, Ltd. | Wimborne, Alberta | 1964 | N | 335 |
| Pamoil | Kessler, Alberta | 1962 | N | 10 |
| Pan American Petroleum | Bigstone, Fox Creek Alberta | 1968 | N | 320 |
| | East Crossfield, Alberta | 1968 | N | 1480 |
| Petrogas Processing, Ltd. | Balzac, Alberta | 1961 | N | 870 |
| | Expansion | 1967 | N | +1100 |
| Saratoga-Jefferson Lake Sulphur | Coleman, Alberta | 1961 | N | 377 |
| Shell Canada, Ltd. | Innisfail, Alberta | 1960 | N | 100 |
| | Jumping Pound, Alberta | 1951 | N | 90 |
| | Jumping Pound West, Alberta | 1967 | N | 140 |
| | Oakville, Ontario | 1963 | R | 46 |
| | Sarnia, Ontario | 1966 | R | 35 |
| | N. Burnaby, B. C. | 1968 | R | :5 |
| | Waterton, Alberta | 1962 | N | 1200 |
| | Expansion | 1967 | N | + 450 |
| | Estevan, Sask. | 1965 | N | 15 |
| Steelman Gas Ltd. | Okotoks, Alberta | 1959 | N | 380 |
| Texas Gulf Sulphur | West Whitecourt, Alberta | 1962 | N | 700 |
| | Expansion | 1965 | N | + 525 |
| | Expansion | 1968 | N | + 650 |
| | Wildhorse Creek, Alberta | 1966 | N | 30 |
| | Expansion | 1968 | N | + 620 |
| Westcoast-Jefferson Lake | Taylor, B.C. | 1957 | N | 325 |

Table 3

## Investment costs for sulfur recovery units

| | | |
|---|---|---|
| Production capacity, LT/D | 18 | 52 |
| Acid-gas analysis, mole % $H_2S$ (dry basis) | 62 | 17 |
| Actual contract cost*, 1952 | $260,000 | $491,000 |
| Contract cost escalated to 1967 construction | | |
| Cost index (1.75 × 1952 cost) | $450,000 | $860,000 |
| Contract cost in 1967 for present design | $160,000 | $430,000 |
| Percent of 1952 plant cost | 62 | 87 |
| Percent of 1967 cost for 1952 plant design | 36 | 50 |

*Both plants had two reactors. Contract cost does not include land, inventory and working capital, owner's overhead and engineering, boiler feed water treating, steam condensation, or incinerator and stack.

Table 4

## Example economics of third reactor

| | | |
|---|---|---|
| Number of reactors per train | 2 | 3 |
| Theoretical sulfur recovery, % | 95.0 | 96.0 |
| Long tons/day | 658 | 665 |
| Investment, U.S. basis | $1,940,000 | $2,270,000 |
| Incremental costs for third reactor, annual | | |
| Operating expense | $ 47,000 | |
| Capital charge at 20% of incremental investment per year | $ 66,000 | |
| Total | $ 113,000 | |
| Incremental sulfur production, LT/YR | 2,800 | |
| Netback sulfur price at plant, $/LT, required to pay incremental operating expense and capital charge | 40 | |

Note: Operating expense includes power for additional blower horsepower, catalyst, maintenance, and insurance.

LT/D do not require the full-time attention of an operator.

The amount of the operator's time assigned to the sulfur recovery plant will often depend on the other duties which are assigned to him in other parts of the overall operations, and how much automation is built into the sulfur plant.

Outside of occasional tests of the residue gas and inspection of the controls, a sulfur-recovery plant normally requires little attention.

However, if the hydrogen sulfide, hydrocarbon, or water content of the acid gas varies, more operating labor or automatic analysis and automatic control of the air rate will be required to maintain high recovery efficiency.

Loading operations are often done by contract labor on a per ton basis. Loading costs for tank cars will vary from 10 to 15¢/LT depending on the amount of sulfur to be loaded, whereas the costs for loading solid sulfur will vary from 55 to 65¢/LT where gondola cars are used and the sulfur must be crushed to size, costs are somewhat higher.

A simplified method of evaluating projects is based on the observation that a 12% rate of return (after tax) on 100% equity investment is obtained if the annual net income before tax is 20% of the investment. This assumes constant income for 20 years, at an income tax rate of 50% and 7% investment tax credit.

The relationship would of course be different for a declining production pattern as would prevail in many natural-gas-processing applications or if the uncertainty of acid-gas feed-supply quantity required a higher rate of return.

On this basis, Fig. 4 summarizes the effect of plant size and feed-gas composition on economics. An example of the calculation method for Fig. 4 is:

| | |
|---|---|
| Sulfur product rate, LT/D | 50 |
| LT/YR | 17,350 |
| Investment (70 mole % $H_2S$ in feed) | |
| Contract price (Fig. 2) | $270,000 |
| Allowance for owners' overhead and engineering, boiler feed-water facilities, and land at 15% | $ 40,500 |
| Total .......................... | $310,500 |
| Annual capital charge at 20% of investment .................. | $ 62,100 |
| Capital charge, $/LT .......... | $ 3.60 |
| Operating expense, $/LT (Fig. 3) | $ 1.50 |
| + electric power for air blower | $ 0.35 |
| Total production cost, $/LT .... | $ 5.45 |

Since investments and operating expenses vary with local conditions and specific design requirements, the values in Fig. 4 should be considered as approximate.

In the above calculation, no charge is included for the acid-gas feed to the sulfur recovery plant and no credit is taken for the value of the produced steam since these factors will vary greatly depending on the specific plant.

The investment and operating cost of an incinerator and dispersal stack are not included, because, depending on the situation, these could be either (a) very expensive, (b) not needed, or (c) represent a net credit, because the sulfur recovery plant reduced the cost of incinerator and stack which air-control regulations would otherwise have required. These factors must be taken into account as appropriate in evaluation of a specific case.

**Third reactor.** One method of increasing the recovery is installation of an additional reactor and condenser system in series.

Three-reactor plants can be designed to achieve recoveries of 96-97%. Table 4 shows an example of the effect of a third reactor on recovery and economics for a 658-LT/D plant which processes a rich acid gas (90 mole % $H_2S$).

The third reactor and condenser increases the investment 17% and the plant recovery 1.0%. The additional reactor would yield a 12% return on investment at a sulfur netback at the plant of about $40/LT.

In smaller plants the sulfur price required to justify use of a third reactor is higher.

Highly sophisticated computer programs have been developed for optimization of the many flow sheet options and operating variables. For example, the recovery of a two-reactor plant can be increased by design changes which add to the plant cost.

It was previously reported[1] that use of gas-to-gas exchange or an in-line burner instead of reheat gas (injection of hot gas from some upstream point in the process) for preheating reactor feed gas can increase the recovery about 0.5% in a two-reactor plant.

Recovery can also be increased by optimization of various plant temperatures. The higher investment required for these design changes can often be justified at present sulfur sales prices.

**Product purity.** Sulfur recovered from acid gas in a Claus-type recovery plant usually has a purity above 99.9%. To maintain this purity requires care in handling, particularly if the material is shipped as a solid.

Availability of material having this purity is advantageous to the sulfuric acid manufacturer since it enables him to reduce his plant investment by eliminating the liquid sulfur inlet filter.

Where storage of sulfur in the solid form at the producing plant is practiced, however, it may be necessary to provide sulfur filtration facilities to assure that remelted sulfur will meet customer specifications.

Since shipment of solid sulfur in gondola cars is common, contamination during shipment is possible. It is therefore important for buyer and seller to agree on the manner of sampling and the point at which the shipment is to be sampled.

Because of the inherent high purity of recovered sulfur, the analytical techniques used to detect impurities require more care and precision for accurate results. Larger sample sizes than used for Frasch sulfur samples are generally advisable, often by factors as large as 20:1.

Off-color sulfur or high organic ash is generally a sign that hydrocarbons are present in the feed to the unit in excess amounts. Heavy hydrocarbons from the plant inlet stream or excessive carry-over of acid-gas solvent are generally the source of carbonaceous materials that color the sulfur.

Inorganic ash in the as-produced sulfur may result from attrition of the catalyst or from wind-borne dust sifting into the storage pits. Where solid sulfur is stored in open blocks, the possibility of atmospheric contamination increases. Care must be taken during the loading of solid sulfur to avoid inclusion of soil from the loading area in the shipment.

Although most specifications for arsenic, selenium and tellurium read "shall be commercially free of arsenic, selenium and tellurium," no literature references are readily available to define the absolute limits.

Communication with analysts whose experience goes back many years or whose experience includes analysis of sulfur recovered from pyrites would indicate that contents less than 0.25 ppm of arsenic, and 2.0 ppm of selenium or tellurium can be considered to be "commercially free."

These limits are given by Texas Gulf Sulphur in their sulfur manual as being maximums for Frasch sulfur as well. It is essential that large-size samples be used, and that blank determinations be run on all reagents. In the past 15 years, the authors have not encountered any recovered sulfur which exceeded these limits.

Plant location and customer requirements may heavily affect storage requirements at sulfur recovery plants. Normally, 3-5 days storage is provided for liquid sulfur and an area set aside for several months' storage of solid sulfur.

In past years, when sulfur was in oversupply, it was not unusual for a customer to expect the supplier to carry several months' supply in storage in order to be considered an acceptable source.

In the recent short-supply situation, customers considered themselves fortunate if they could supply their entire demand without allocation.

Plants from which offshore shipments are made may require more solid storage than would otherwise be required. Cargoes of sulfur are generally in multiples of 10,000 metric tons.

Storage of at least this amount will be needed either at the plant or at the port unless the outputs of several small plants can be dedicated to a specific shipment.

The latter requires coordination of both production and shipping facilities if excess demurrage and port storage charges are to be avoided.

Location of solid storage areas should be chosen, keeping in mind:

1. Location of recovery facilities.
2. Accessibility to rail and truck-loading facilities.
3. Wind direction.
4. Proximity to land under cultivation.

**More production.** The increase in range of $H_2S$ concentration in acid gas to be processed is due to two factors; increase in sulfur prices and air-quality regulations.

Recovered sulfur has come largely from acid gas removed from natural gas or from refinery gases. Another source of sulfur with vast potential is stack gases. It has been estimated that 12,700,000 LT of sulfur from all sources was emitted to the atmosphere in the United States in 1966.[4]

Many processes for removal of sulfur compounds from stack gases are being proposed. All of the processes proposed to date, however, are expensive.

Because of regulations restricting $SO_2$ emissions in the more populated areas of the U.S., it is probably that economic methods to process stack gases to recover sulfur will be developed.[5]

According to Archie V. Slack of TVA in a paper delivered at the 154th National Meeting of the American Chemical Society, sulfur recovered from power-plant stack gases could become a major raw material source for the fertilizer industry.

Mr. Slack estimates that by 1970 sulfur dioxide equivalent to 8 million tons/year of sulfur will be emitted from power plants alone burning coal and fuel oil.

However, because of the rapidly increasing world demand, sulfur recovered from this source should remain a small percentage of the world sulfur consumption.

Increased prices have also stimulated increased interest in sulfur exploration, particularly offshore in the Gulf Coast and in West Texas. Results offshore to date have not been outstanding.[6] In the Federal Offshore-Texas Sulfur lease sale held in December 1965, a total of 70,560 acres were purchased for $33,740,000 for an average of $480/acre.

No announcement of a sulfur discovery has been made by any of the leaseholders. Elcor Chemical Co. has announced[7] a new process for recovery of 1,000 long tons/day of sulfur from gypsum in Culberson County, West Texas. New, unique Frasch operations are starting for the first time in the U.S., where the Frasch method has been used on a deposit not associated with a salt dome.

The Duval Corp. has let a contract to construct[8] a Frasch operation in the same county, which will recover 2,500,000 LT/YR. Duval will complete expansion of the Pecos County Frasch operation to 350,000 LT/YR. Sinclair has a smaller Frasch operation in the same general area.

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# APPENDIX F - ELCOR CHEMICAL CORPORATION INFORMATION

February 18, 1972

Mr. William Haggard
Elcor Chemical Corporation
Wilco Building
Midland, Texas 79701

Subject: Claus Sulfur Plant
Performance

Dear Mr. Haggard:

Several of the methods being considered for abatement of sulfur emissions to the atmosphere include Claus sulfur units. The Environmental Protection Agency Office of Air Programs has engaged Processes Research, Inc., to study the efficacy of Claus sulfur plants in pollution abatement (Contract No. 68-02-0242).

We understand that your company operates Claus units recovering sulfur which would otherwise be emitted to the atmosphere. Please let us have available information regarding the performance of these units, as follows. The Office of Air Programs interest is in developing pollution control methods and the requested information is for use in these efforts.

1. Location, daily sulfur capacity, days of operation annually and annual sulfur production.
2. Claus process variation used: straight through, split flow, direct oxidation, sulfur recycle, etc.
3. Number of catalytic stages and method of reheating process vapor.
4. Source, quantity and composition of acid gas feed.
5. Quantity and composition of tail gas.
6. Incineration or other tail gas treatment.
7. Frequency of catalyst change and maintenance.

8. Operator attendance and trouble.

9. Consumption and generation of fuel, water, power and steam.

If some of this information is available for one or more of your Claus units, please let us know when we may expect to receive it. We thank you for your cooperation.

Very truly yours,

PROCESSES RESEARCH, INC.

W. D. Beers
Project Manager

WDB/mk

cc: G. S. Haselberger
M. R. Jester
P. W. Spaite

ELCOR
CHEMICAL CORPORATION
WILCO BUILDING MIDLAND, TEXAS 79701 915 683 4271

March 3, 1972

Mr. W. D. Beers
Process Research, Inc.
Industrial Planning and Research
2912 Vernon Place
Cincinnati, Ohio 45219

Dear Mr. Beers:

In answer to your letter of February 18, 1972, we are pleased to supply information regarding Claus sulfur plant performance:

1. We have one sulfur plant in operation, the Fashing Plant located in Atascosa County, Texas, which we designed and constructed. It has a capacity of approximately 55 long tons per day but is limited by available feed gas to approximately 40 tons per day. It operates throughout the year except for occasional down time for maintenance. Sulfur production during 1971 was 13,500 L.T.

2. The process used is the Split Flow.

3. The plant has two catalytic stages and uses bypass reheating.

4. The source of feed to the sulfur plant is the acid gas stream removed from Lone Star Gas Company's Fashing gas processing plant. The composition is approximately 82% carbon dioxide and 18% $H_2S$.

5. We do not have a recent analysis of the tail gas, but it is essentially all nitrogen carbon dioxide and water vapor.

6. There is no additional treatment beyond the two catalytic reactors.

7. Catalyst change is required every five to seven years.

8. The plant is relatively trouble free.

9. The plant is essentially self-sufficient except for minor amounts of fuel, water and steam supplied by the adjacent Lone Star Plant and the electrical power supplied by the local power company.

I hope this information is of some assistance in your analysis of the Claus process.

Very truly yours,

ELCOR CHEMICAL CORPORATION

W. J. Haggard

W. J. Haggard

WJH:jm

# APPENDIX G - SHELL OIL COMPANY INFORMATION

February 18, 1972

Mr. L. P. Haxby
Manager of Environmental Conservation
Shell Oil Company
One Shell Plaza
P. O. Box 2463
Houston, Texas 77001

Subject: Claus Sulfur Plant Performance

Dear Mr. Haxby:

Several of the methods being considered for abatement of sulfur emissions to the atmosphere include Claus sulfur units. The Environmental Protection Agency Office of Air Programs has engaged Processes Research, Inc., to study the efficacy of Claus sulfur plants in pollution abatement (Contract No. 68-02-0242).

We understand that your company operates Claus units recovering sulfur which would otherwise be emitted to the atmosphere. Please let us have available information regarding the performance of these units, as follows. The Office of Air Programs interest is in developing pollution control methods and the requested information is for use in these efforts.

1. Location, daily sulfur capacity, days of operation annually and annual sulfur production.

2. Claus process variation used: straight through, split flow, direct oxidation, sulfur recycle, etc.

3. Number of catalytic stages and method of reheating process vapor.

4. Source, quantity and composition of acid gas feed.

5. Quantity and composition of tail gas.

6. Incineration or other tail gas treatment.

7. Frequency of catalyst change and maintenance.

8. Operator attendance and trouble.

9. Consumption and generation of fuel, water, power and steam.

If some of this information is available for one or more of your Claus units, please let us know when we may expect to receive it. We thank you for your cooperation.

Very truly yours,

PROCESSES RESEARCH, INC.

W. D. Beers
Project Manager

WDB:mer

cc: G. S. Haselberger
M. R. Jester
P. W. Spaite

SHELL OIL COMPANY
ONE SHELL PLAZA
P.O. BOX 2463
HOUSTON, TEXAS 77001

RECEIVED
[illegible]
'72 APR 19 AM 9:36
A. I. KINNEY, INC
PRO. RESEARCH INC

April 17, 1972

Mr. W. D. Beers
Project Manager
Processes Research, Inc.
2912 Vernon Place
Cincinnati, Ohio 45219

Dear Mr. Beers:

Please refer to your letter of February 18, 1972, requesting certain operating data on commercial Claus sulfur units for inclusion in a report you are preparing for the Environmental Protection Agency (Contract No. 68-02-0242). On the basis of your letter and subsequent telephone contacts with Mr. Thomas of your company, we understand that the purpose of the study you are conducting is to assess the efficacy of such type units in emission abatement programs. We further understand that, for your purposes, it is not necessary that the location of the plants be disclosed.

In the belief that it would prove useful in your report to include data on plants of various sizes, we requested our operating groups to supply information on each; a large, medium, and relatively small sized unit. These data now have been made available to us and, at this time, we are transmitting them to you, attached. We hope the delay has not interfered seriously in meeting your "deadlines". As you will note, our data are arranged, in the interest of uniformity, in the same context as were the several points you raised in your letter.

We trust this information will suffice for your needs. Please let us know if we can be of further assistance.

Very truly yours,

L. P. Haxby

EWS:sw

L. P. Haxby, Manager
Environmental Conservation Department

Attachment

cc - Mr. Thomas, Process Research, Inc.

## CLAUS SULFUR PLANT UNITS

| | | Plant A | Plant B | Plant C |
|---|---|---|---|---|
| 1. | a) daily sulfur production, long tons/day | 185 | 120 | about 40 |
| | b) days of operation annually | 353 | 345 | 320 |
| | c) annual sulfur production, long tons/yr. | 65,000 | 41,500 | 11,600 |
| 2. | a) process "variations" | ← straight through → | | |
| 3. | a) number of stages | 3 | 3 | 2 |
| | b) method of reheating vapor | note 1 | steam | hot by-pass |
| 4. | a) acid gas feed source | note 2 | note 3 | note 4 |
| | b) quantity, MCF/D | 7,600 | 2,300 | 1,500 |
| | c) composition, % (note 5) | | | |
| | $H_2S$ | 68 | 90 | 71 |
| | $CO_2$ | 30 | 8 | 25 |
| | hydrocarbons | 2 | 2 | 4 |
| 5. | a) tail gas quantity, MCF/D | 14,000 | 6,500 | 4,000 |
| | b) tail gas composition, % | | | |
| | $H_2S$ | 0.40 | 1. | - |
| | $N_2$ | 79. | 65. | - |
| | $CO_2$ | 17.5 | 3.5 | - |
| | CO | 2.5 | - | - |
| | $SO_2$ | 0.24 | 0.5 | 8,000-10,000 ppm |
| | $H_2O$ | - | 30. | - |
| 6. | a) tail gas treatment | ← incineration → | | |
| 7. | a) catalyst change frequency | note 6 | ca. 18 mos. | note 6 |
| 8. | a) operator attendance | 126/hrs/wk | 168 hrs/wk | 78 hrs/wk |
| | b) operating troubles | note 7 | note 8 | note 9 |
| 9. | utilities | | | |
| | a) fuel gas, MCF/day | 500 | 192 | 250 |
| | b) steam generated, lbs/hr. | 34,000 | 35,000* | 8000-9000 |

note 1 side stream of acid gas is burned in in-line burners after condenser
note 2 sulfinal process gas sweetening plant discharge
note 3 crude oil refining process
note 4 DEA scrubber/ethylene plant
note 5 excludine trace amounts, if any, of $N_2$ and $H_2O$
note 6 approximately once every three years
note 7 regeneration of catalyst beds, maintenance of 2:1 ratio of $H_2S$ to $SO_2$, maintenance of hydrocarbon recovery unit which is required to minimize carry-over of hydrocarbons to sulfur plant
note 8 none reported
note 9 low throughput lowers efficiency, ineffective demister mat.

*consisting of about 26,500#/hr of 300 psig steam and about 9,00#/hr of 50 psig steam.

## APPENDIX H - STAUFFER CHEMICAL COMPANY INFORMATION

February 18, 1972

Mr. D. M. Roberts
Vice President of Engineering
Stauffer Chemical Corporation
J. B. Cosson Engineering Center
Dobbs Ferry, New York 10522

Subject: Claus Sulfur Plant Performance

Dear Mr. Roberts:

Several of the methods being considered for abatement of sulfur emissions to the atmosphere include Claus sulfur units. The Environmental Protection Agency Office of Air Programs has engaged Processes Research, Inc., to study the efficacy of Claus sulfur plants in pollution abatement (Contract No. 68-02-0242).

We understand that your company operates Claus units recovering sulfur which would otherwise be emitted to the atmosphere. Please let us have available information regarding the performance of these units, as follows. The Office of Air Programs interest is in developing pollution control methods and the requested information is for use in these efforts.

1. Location, daily sulfur capacity, days of operation annually and annual sulfur production.

2. Claus process variation used: straight through, split flow, direct oxidation, sulfur recycle, etc.

3. Number of catalytic stages and method of reheating process vapor.

4. Source, quantity and composition of acid gas feed.

5. Quantity and composition of tail gas.

6. Incineration or other tail gas treatment.

7. Frequency of catalyst change and maintenance.

8. Operator attendance and trouble.

9. Consumption and generation of fuel, water, power and steam.

If some of this information is available for one or more of your Claus units, please let us know when we may expect to receive it. We thank you for your cooperation.

Very truly yours,

PROCESSES RESEARCH, INC.

W. D. Beers
Project Manager

WDS:fj

cc: G. S. Haselberger
M. R. Jester
P. W. Spaite

[illegible]
ENGINEERING CENTER

Stauffer
CHEMICALS

Stauffer Chemical Company
Dobbs Ferry, New York 10522 / Telephone (Area Code 914) OWens 3-1200

RECEIVED
'72 APR 3 AM 10:08

March 21, 1972

A.M. KINNEY, INC.
PRO. RESEARCH INC.

Mr. W. D. Beers
Project Manager
Processes Research Inc.
Industrial Planning and Research
2912 Vernon Place
Cincinnati, Ohio 45219

Subject: Claus Sulfur Plants

Reference: Letter from W. D. Beers to D. H. Roberts dated February 18, 1972

Gentlemen:

The following information is from various Stauffer Chemical Company Claus Sulfur Recovery Plants. The data as listed is in accordance with the referenced letter.

| 1. a. Plant Location | Baytown, Texas | Delaware City, Del. | Le Moyne, Ala. | Long Beach, Calif. |
|---|---|---|---|---|
| b. Daily Sulfur Capacity T/D | 100 | 400 | 250 | 450 (4 units) |
| c. Day of Operation Annually | 335 | 335 | 335 | 335 |
| d. Annual Sulfur Production | 33,500 | 134,000 | 83,750 | 150,750 |
| 2. Claus Process Variation | Straight Through | Straight Through | Straight Through | Straight Through |
| 3. Number of Catalytic Stages | 2 | 2 | 2 | 2 |

| | | | | | |
|---|---|---|---|---|---|
| b. | Method of Reheating Process Vapor | In-line Burners | In-line Burners | In-line Burners | In-line Burners |
| 4. a. | Acid Feed Gas Source | Refinery | $CS_2$ Plant | $CS_2$ Plant | Refinery |
| b. | Quantity-SCFM | 2800 | 7680 | 4130 | 4480 |
| c. | Composition-% $H_2S$ | 50.3 | 96.3 | 95.5 | 83.5 |
| | $N_2$ | 1.0 | 0.2 | 0.4 | 0.4 |
| | $CO_2$ | 46.1 | 0.2 | 0.6 | 11.5 |
| | $CH_4$ | 2.5 | 3.2 | 3.4 | 0.5 |
| | $H_2O$ | - | - | - | 4.0 |
| | $CS_2$ | - | 0.2 | 0.5 | - |
| | $NH_3$ | - | - | - | 0.1 |
| 5. a. | Tail Gas-Quantity-SCFM | 6250 | 20,760 | 13,200 | 25,320 |
| b. | Composition-% $H_2S$ | 0.7 | 0.9 | 1.0 | 0.8 |
| | $SO_2$ | 0.3 | 0.4 | 0.5 | 0.4 |
| | S | 0.2 | 0.3 | 0.3 | 0.3 |
| | $CO_2$ | 21.8 | 1.1 | 1.3 | 4.4 |
| | $N_2$ | 51.5 | 64.2 | 64.3 | 60.2 |
| | $H_2O$ | 25.5 | 33.1 | 32.6 | 33.9 |
| 6. | Gas Treatment | Incineration | Incineration | Incineration | Incineration |
| 7. | Frequency of Catalyst Change Approx. Years | 5 | 5 | 5 | 5 |

| | | | | |
|---|---|---|---|---|
| 8. a. Operator Attendance-Time | 1/4 | 1/4 | 1/4 | 1/4 |
| b. Trouble | Very low | Very low | Very low | Very low |
| 9. Consumption/ Generation | | | | |
| a. Gas SCFM | - | 191 | 130 | 460 |
| b. Steam | Consumed within Plant | Consumed within Plant | Consumed within Plant | Consumed within Plant |
| c. Power | - | - | - | - |

I hope the above information will satisfy your requirements in completing your study under Contract No. 68-02-0242.

Very truly yours,

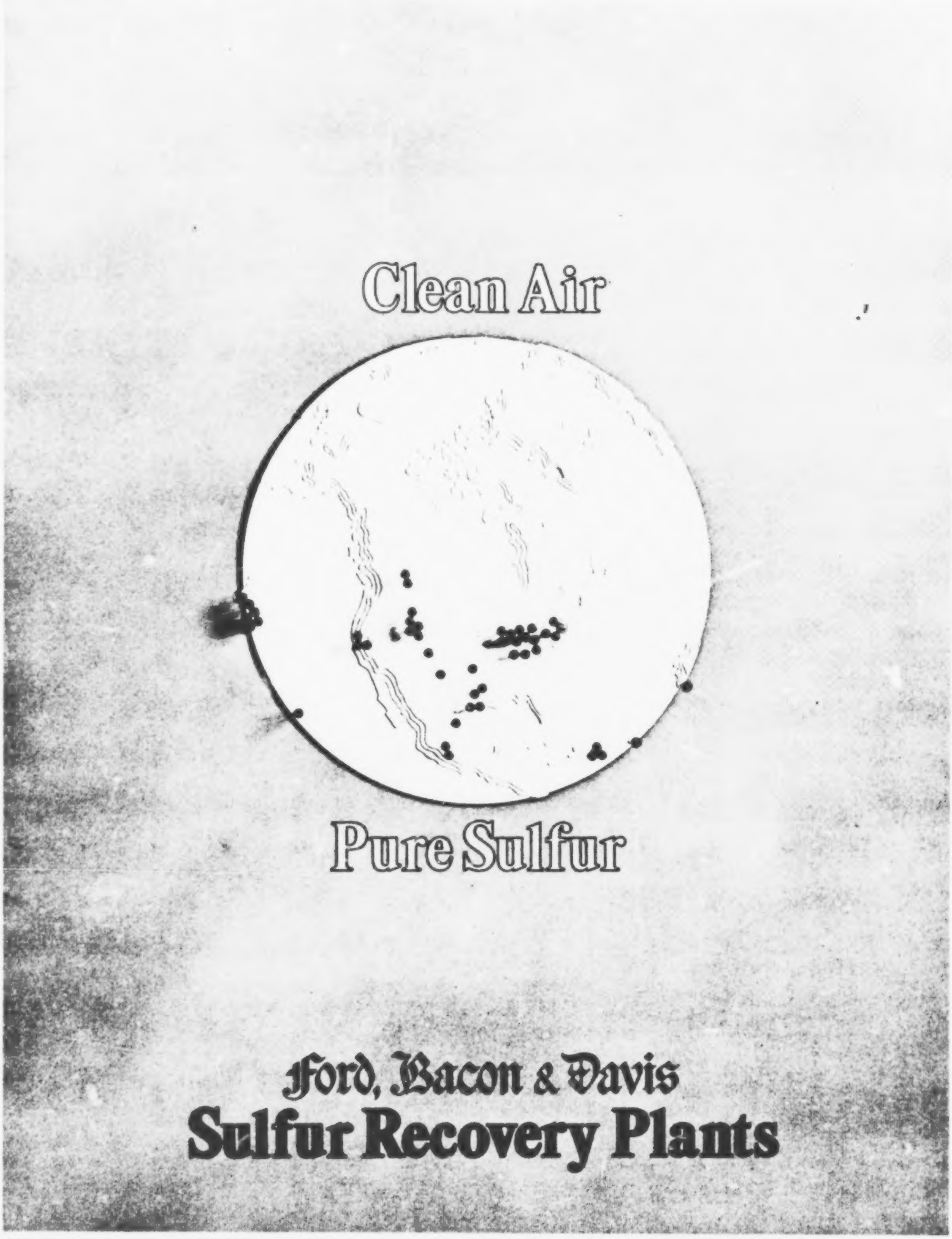
STAUFFER CHEMICAL COMPANY

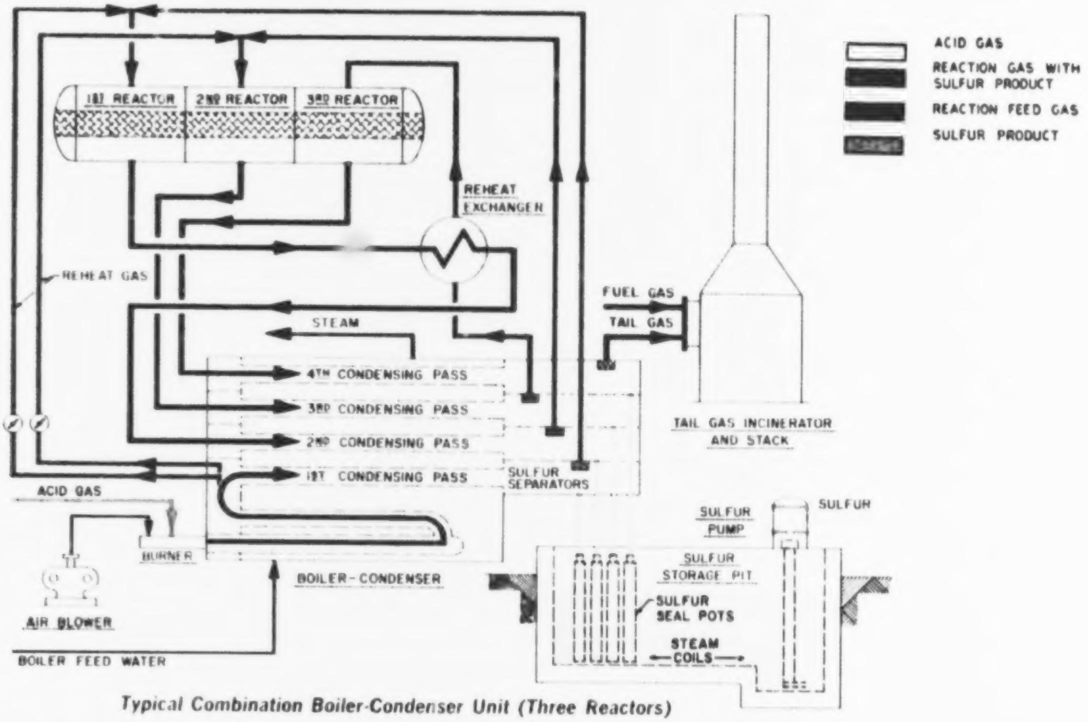
L L Zuber

L. L. Zuber
Sr. Project Engineer

LLZ:gm
Encl.

## APPENDIX I - FORD, BACON & DAVIS INFORMATION


Clean Air
Pure Sulfur
Ford, Bacon & Davis
Sulfur Recovery Plants


ACID GAS
REACTION GAS WITH SULFUR PRODUCT
REACTION FEED GAS
SULFUR PRODUCT
1ST REACTOR
2ND REACTOR
3RD REACTOR
REHEAT EXCHANGER
REHEAT GAS
STEAM
FUEL GAS
TAIL GAS
4TH CONDENSING PASS
3RD CONDENSING PASS
2ND CONDENSING PASS
1ST CONDENSING PASS
SULFUR SEPARATORS
TAIL GAS INCINERATOR AND STACK
ACID GAS
BURNER
AIR BLOWER
BOILER FEED WATER
BOILER-CONDENSER
SULFUR PUMP
SULFUR
SULFUR STORAGE PIT
SULFUR SEAL POTS
STEAM COILS

*Typical Combination Boiler-Condenser Unit (Three Reactors)*

# Ford, Bacon & Davis Sulfur Recovery Plants

are a modern-day improvement of the original Claus process for recovering sulfur from hydrogen sulfide gas. There are more of these type plants being installed domestically than any other, Ford, Bacon & Davis having completed more than 45 projects.

Most of Ford, Bacon & Davis' plants have been custom-designed and constructed for refinery and chemical plant applications to process the actual gas stream available. Except for the very smallest units, custom-designed plants have proven to provide a much more satisfactory installation than a skid-mounted or an off-the-shelf design, which often compromise efficiency and operation of the plant for the sake of compactness.

FB&D plants are exceptionally flexible, and normally can be operated at a rate of as low as one-third of design capacity. Special-design plants allow operation at even lower capacities.

Ford, Bacon & Davis, as a national engineering-contractor, offers complete process design, detail engineering, procurement, construction, and start-up services, anywhere in the Northern Hemisphere, and design and procurement services anywhere in the world.

The principal feature of the process described herein is a unique, patented vessel arrangement referred to as a boiler-condenser. This vessel, illustrated above, combines into one piece of equipment several functions, such as burning the $H_2S$ gas, cooling and condensing the sulfur, separating the sulfur product from the gas, and producing steam. This design has been proven to provide a high-quality unit with maximum recovery levels and easy operation at much lower costs than is possible with the older-style Claus plants that require as many as six vessels to accomplish the various functions.

In very large plants where a single vessel would be too large, or where high-pressure steam generation is desired, a boiler and a single, separate condenser can be provided as shown on Page 3. This also provides extensive cost savings and simplicity of operation, compared to using several separate condensers.

The reactors are also combined in a single vessel, as shown above, unless the size of the vessel becomes impracticable, in which case they are separated as shown on Page 3. Also, because of increasingly-strict pollution requirements, the use of three reactors is now often required to meet codes (in certain areas the third reactor is mandatory). In many applications, the third reactor can be justified economically, because the stack height can be reduced due to the higher recovery levels.

In addition, we have also designed a number of plants to process gas streams that contain potentially-troublesome components such as ammonia, hydrocarbons, $CS_2$, and COS. The process shown on Page 3 also includes a separate combustion chamber which is provided as part of the design where required to properly handle large concentrations of these components.

*Cost estimates and utility requirements can be furnished from these data:* Feed gas analysis (volume; temperature; pressure), steam pressures available or desired, utilities available, site location and ambient conditions, storage requirements, and recovery and $SO_2$ limitations (if any).

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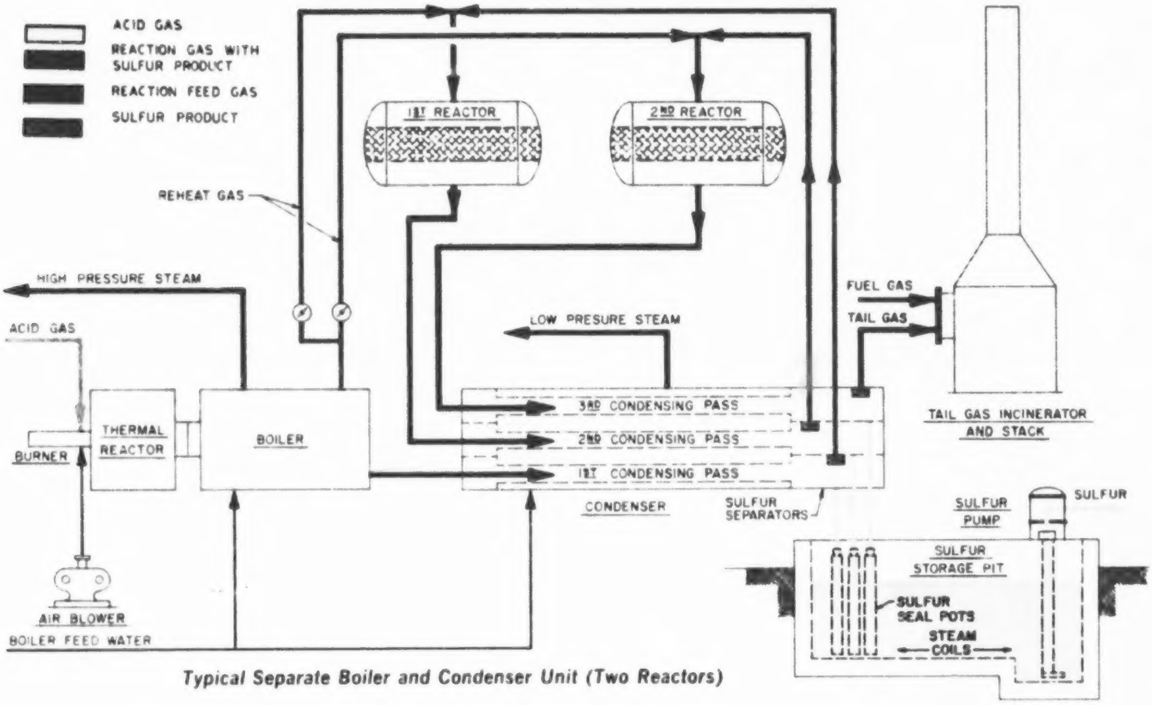

ACID GAS
REACTION GAS WITH SULFUR PRODUCT
REACTION FEED GAS
SULFUR PRODUCT
1ST REACTOR
2ND REACTOR
REHEAT GAS
HIGH PRESSURE STEAM
ACID GAS
LOW PRESURE STEAM
FUEL GAS
TAIL GAS
THERMAL REACTOR
BURNER
BOILER
3RD CONDENSING PASS
2ND CONDENSING PASS
1ST CONDENSING PASS
CONDENSER
SULFUR SEPARATORS
TAIL GAS INCINERATOR AND STACK
SULFUR PUMP
SULFUR
SULFUR STORAGE PIT
SULFUR SEAL POTS
STEAM COILS
AIR BLOWER
BOILER FEED WATER

***Typical Separate Boiler and Condenser Unit (Two Reactors)***

# How the Plants Operate

The Claus process involves the combustion of approximately one-third of the $H_2S$ to $SO_2$ and the subsequent reaction between the remaining $H_2S$ and the produced $SO_2$ to form sulfur and water vapor, with the subsequent recovery of the sulfur product.

Ford, Bacon & Davis offers the modernized Claus process in two basic process schemes, referred to as *straight-through* and *split-flow*. The most common application is the straight-through process, which is illustrated in two versions (above and on the facing page), wherein all of the acid gas is fed through the burner. This process is used for most acid gas streams that contain high concentrations of $H_2S$, generally in the range of 50 per cent or higher, such as the off-gas from a typical amine unit in a refinery. Our process can provide the highest recovery level available from the Claus-type process. Also, we are licensed for various other processes to recover additional sulfur from the tail gas from the Claus process, which provide even higher recoveries.

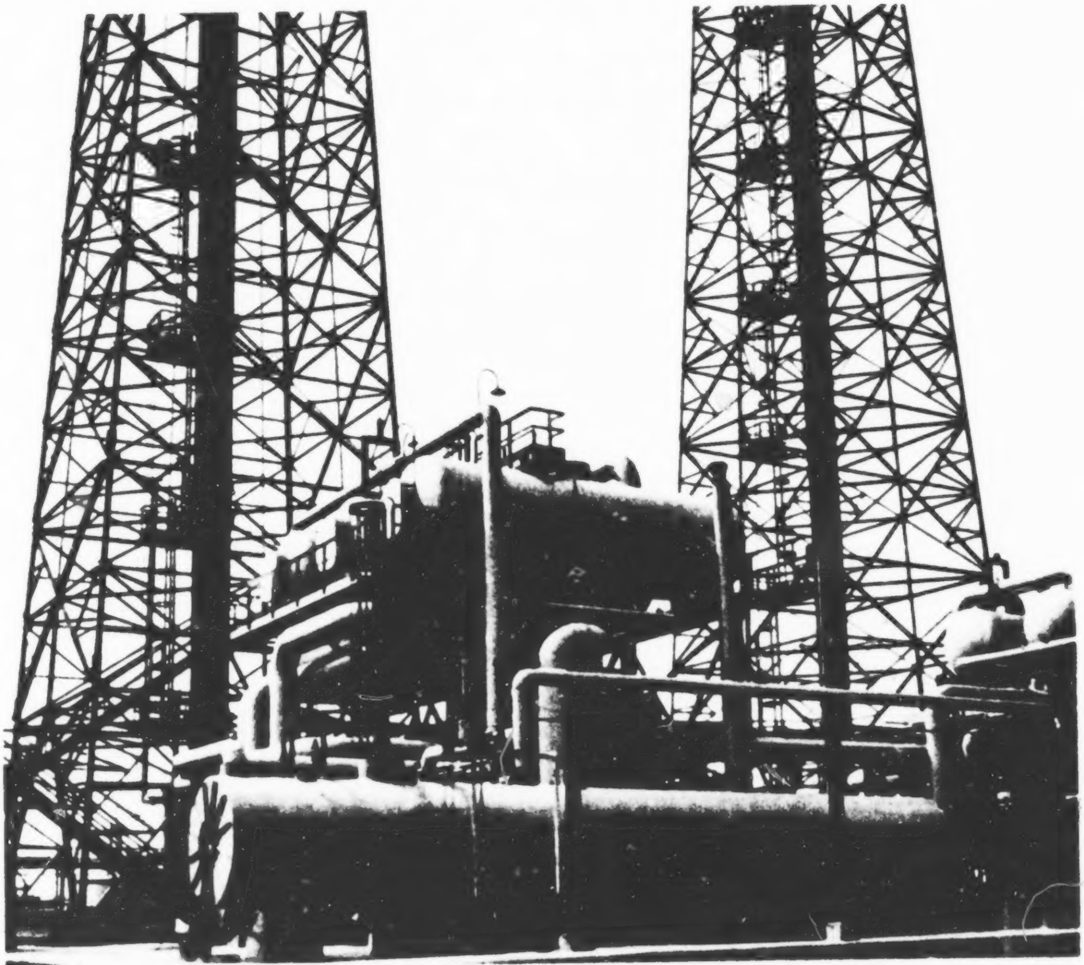
The split-flow process is required for lean acid gas streams of less than 50 per cent $H_2S$, such as are found in certain gas fields where high concentrations of $CO_2$ are present. In the typical split-flow unit, as much of the acid gas as possible, without adversely affecting combustion, is fed to the burner in the combustion chamber with air, where a large percentage of the $H_2S$ is combusted to $SO_2$. The remainder of the acid gas is mixed with the boiler effluent and fed directly to the reactor. The process is designed in this way since the flame could not be maintained if all of the acid gas were fed to the burner, as in the design of a straight-through unit, due to the inerts present.

In the straight-through process, all of the acid gas and the combustion air are fed through a special burner where one-third of the $H_2S$ is burned to $SO_2$. Effluent from the second cooling pass, containing sulfur vapor created from the non-catalytic reaction between the $H_2S$ and $SO_2$ in the first two passes, is condensed in the first condensing pass. The sulfur product, which is recovered in the first separator, is drained to storage. Gases from the first separator are reheated with a hot gas by-pass stream from the second boiler pass to provide the necessary reaction temperature. This is also the reheat method used on the second reactor feed. Other reheat methods can be used which provide higher recoveries, but at relatively higher costs.

Sulfur vapor is produced in the first reactor from the reaction between the $H_2S$ and $SO_2$ in the presence of a bauxite catalyst. The resulting sulfur vapor from the catalytic reaction is condensed in the second condensing pass, separated in the second separator, and drained to storage. The conversion and recovery cycle is repeated in the second and third reactors and the other condensing passes and separators. When a third reactor is used, the reaction feed gas is normally heated in a reheat exchanger to reaction temperature by using the first reaction effluent.

The incinerator converts the sulfur compounds remaining in the tail gas from the plant to $SO_2$. The design normally provides for a tail gas stack of sufficient height to meet local pollution code limitations on $SO_2$ concentration at grade.

Normally, a concrete sulfur storage pit is provided to store the sulfur in a molten state for loading into trucks or rail cars. The sulfur is kept molten with steam produced in the plant. A steel storage tank is sometimes used on smaller or skid-mounted units.



Two 135 LTD sulfur recovery units with 300' derrick supported stacks • Humble Oil and Refining Co., Bayway Refinery, Linden, New Jersey

# Operating and Maintenance Costs

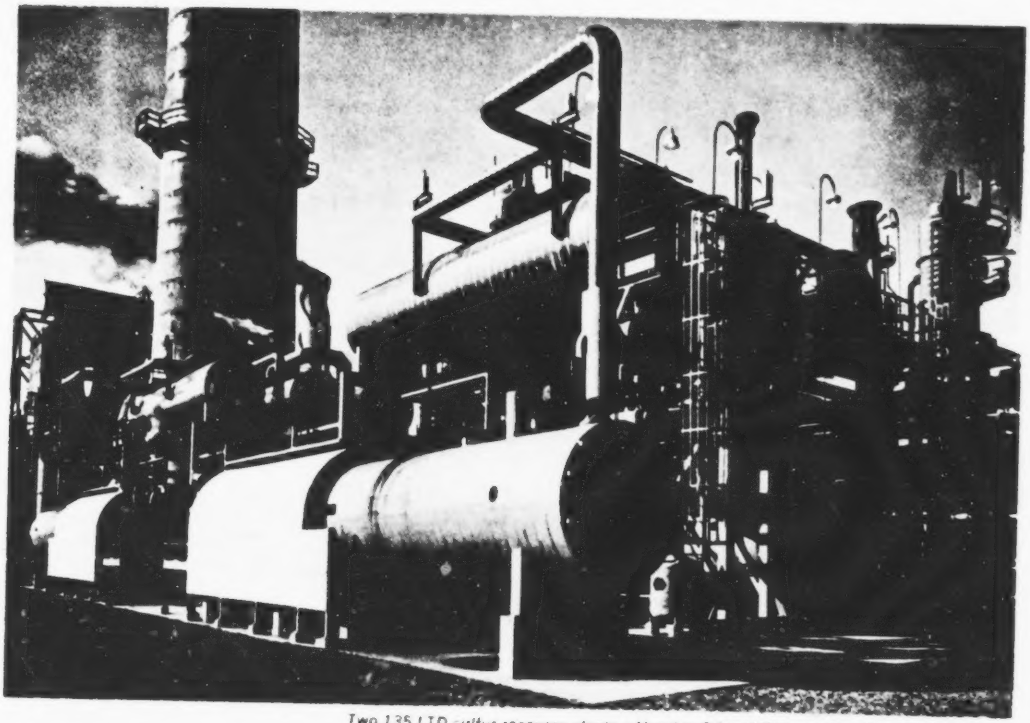
Extensive automatic controls are provided to allow FB&D plants to operate virtually unattended and to shut down the plant in the event of a hazardous malfunction. Only one to two manhours of supervision per twenty-four hours of operation are normally needed.

Utilities required for the plant are nominal. The connected electric load is approximately 2 horsepower per ton of production, most of which is required for the air blower, with a small amount required for the intermittent operation of the sulfur pump, lighting, etc. Fuel gas is required only for start-up of the sulfur plant and operation of the tail gas incinerator. Instrument air or gas of 3 to 4 s.c.f.m. and treated boiler feed water for the quantity of steam produced are the only other utilities required.

The unit will produce approximately 250 pounds of steam per hour per ton of sulfur production. The value of the steam that is produced will normally offset the cost of the utilities required for the unit. If the steam cannot be used, it can be condensed and returned to the boiler-condenser.

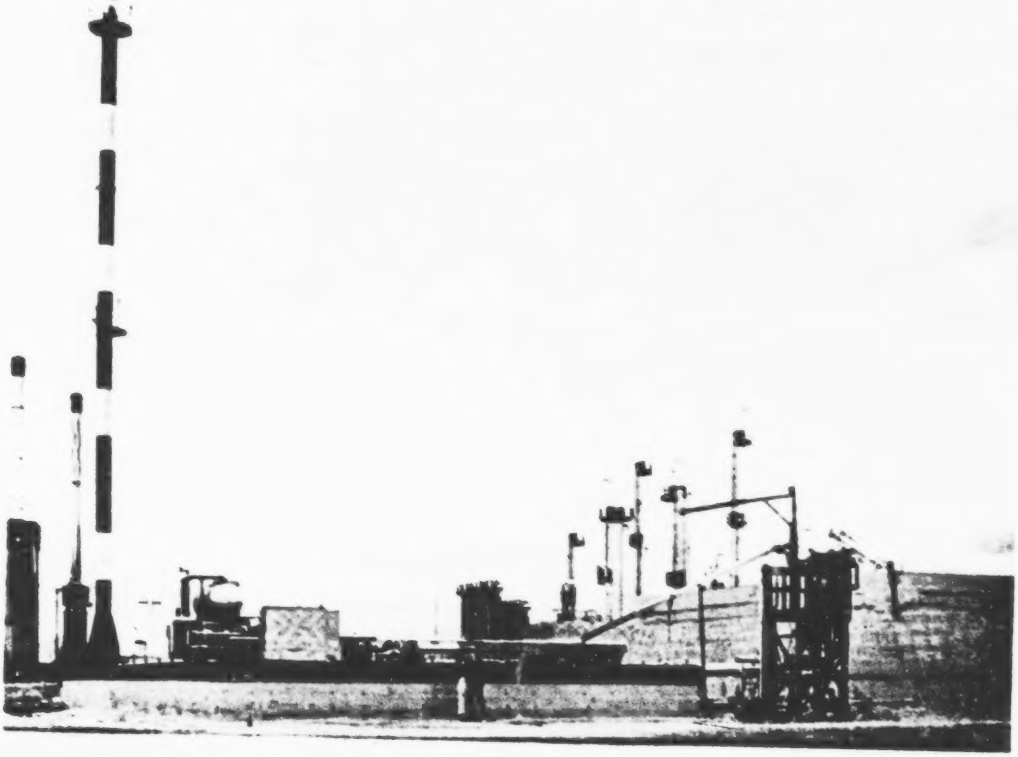
The most economical plant is a single boiler-condenser producing all the steam in the 20 to 150 p.s.i.g. range. In the larger units, or where high-pressure steam is required (wherein the boiler is separated from the condenser), as much as two-thirds of the steam can be produced at higher pressures (up to 550 p.s.i.g.).

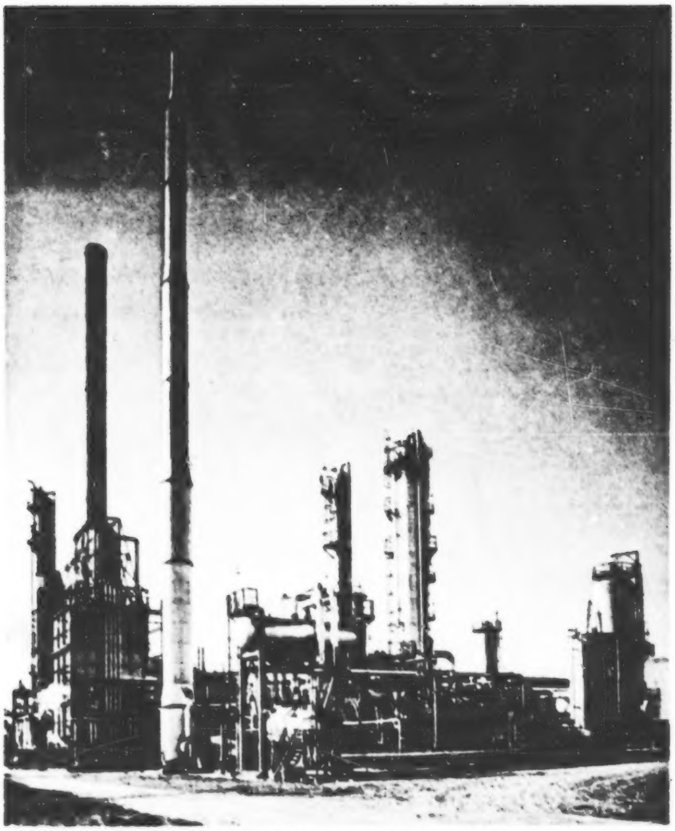
Maintenance costs are normally less than 1 to 2 per cent per year of installed cost, due to the small amount of rotating equipment, lack of corrosion, etc. Catalyst is inexpensive, and normally has a minimum life of from three to five years.



*Two 135 LTD sulfur recovery plants • Humble Oil and Refining Co., Benicia, California*

*18 LTD sulfur recovery plant with guy-supported tail gas stack • Hudson's Bay Oil and Gas Co. Ltd., Sundre, Alberta*





*Sulfur recovery and amine treating units specifically designed to process 5 to 50 tons of sulfur per day (Canton, Ohio). A duplicate facility was also completed at Buffalo, New York • Ashland Oil Co.*

# Amine Treating and Related Projects

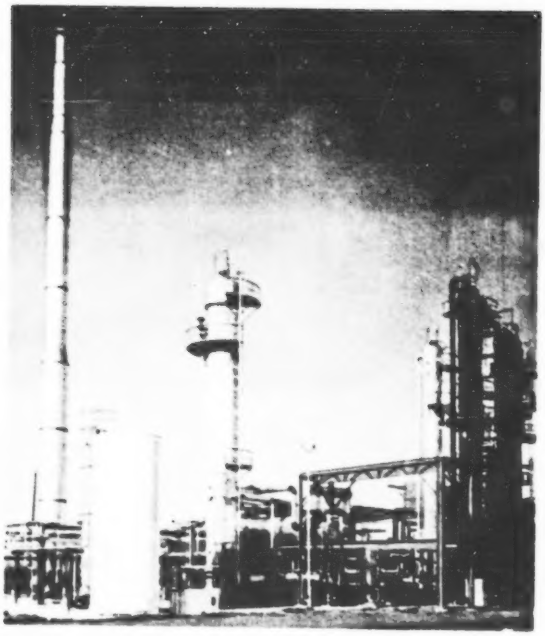
Ford, Bacon & Davis also offers extensive experience in amine treating and related facilities as well as in sulfur recovery. We are also licensed to use various treating processes, such as Shell's Sulfinol, and many gas sweetening units of all types have been completed in connection with sulfur recovery facilities, including both MEA and DEA. A DEA (amine) unit will be required for refinery installations where $CS_2$, COS, or other contaminants are present which would cause problems such as fouling an MEA solution. The MEA (amine) unit is normally used in natural gas service and where certain contaminants are not present in refining units.

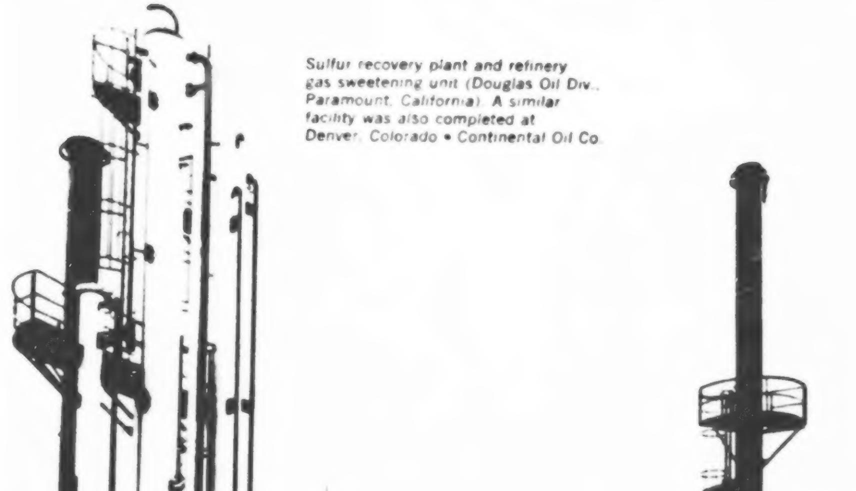
Since amine treating or other gas sweetening units normally are required in conjunction with, and are adjacent to, sulfur recovery facilities, there is merit in considering the award of a single contract to include these units with the sulfur plant.

One very important advantage in combining more than one unit into a single contract is the ability to manage the construction as a single project, which greatly reduces the indirect field and home office costs when compared to two separate projects. The majority of the turn-key facilities we install include both amine and sulfur plants as a single project. Thus our experience is comparable in both areas.

## Tail Gas Recovery Processes

Ford, Bacon & Davis is also licensed for various processes to recover sulfur compounds from the tail gas of sulfur plants, in order to increase recovery levels, and to meet increasingly stringent air pollution codes ($SO_2$ emission). These processes can be installed in conjunction with Ford, Bacon & Davis sulfur recovery plants when built, or for existing sulfur plants.





Sulfur recovery plant and refinery gas sweetening unit (Douglas Oil Div., Paramount, California). A similar facility was also completed at Denver, Colorado • Continental Oil Co.

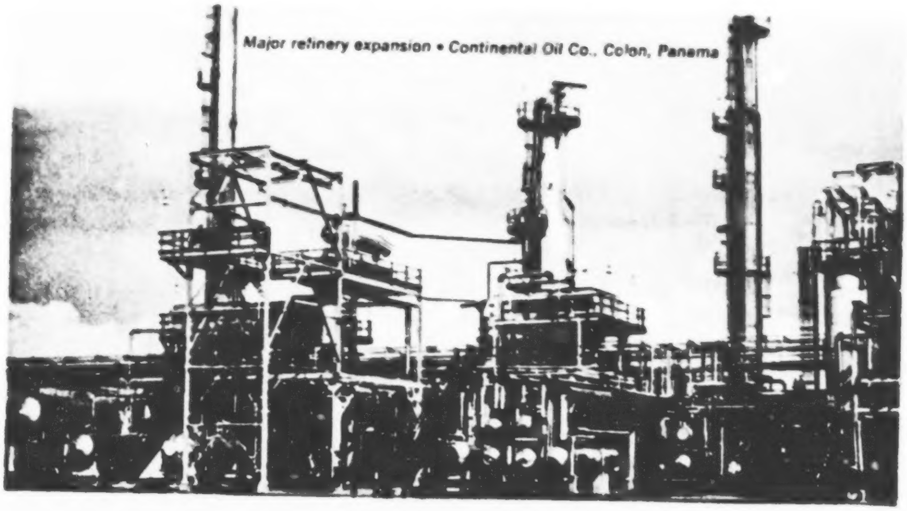
Expansion of reformer facilities • Skelly Oil Co., El Dorado, Kansas

**Ford, Bacon & Davis** has a wide range of experience in process design, engineering, and construction in a wide range of related facilities —

• Petrochemical Plants • Oil Refining and Processing Plants • Natural Gas Processing Installations • Compressor Stations • Offsite Facilities • Industrial Plants • Mining and Materials Handling Facilities • Power Plants • Pipe Lines • Municipal Facilities • Paper Mills • Industrial Engineering • Appraisals and Valuations

**PROCESS PLANT DIVISION** 2908 National Drive (Garland) • P.O. Box 38209 • Dallas, Texas U.S.A. 75238 • 214/278-8121

Also Monroe • Tulsa • Baton Rouge • New York • Calgary • Brisbane



Major refinery expansion • Continental Oil Co., Colon, Panama

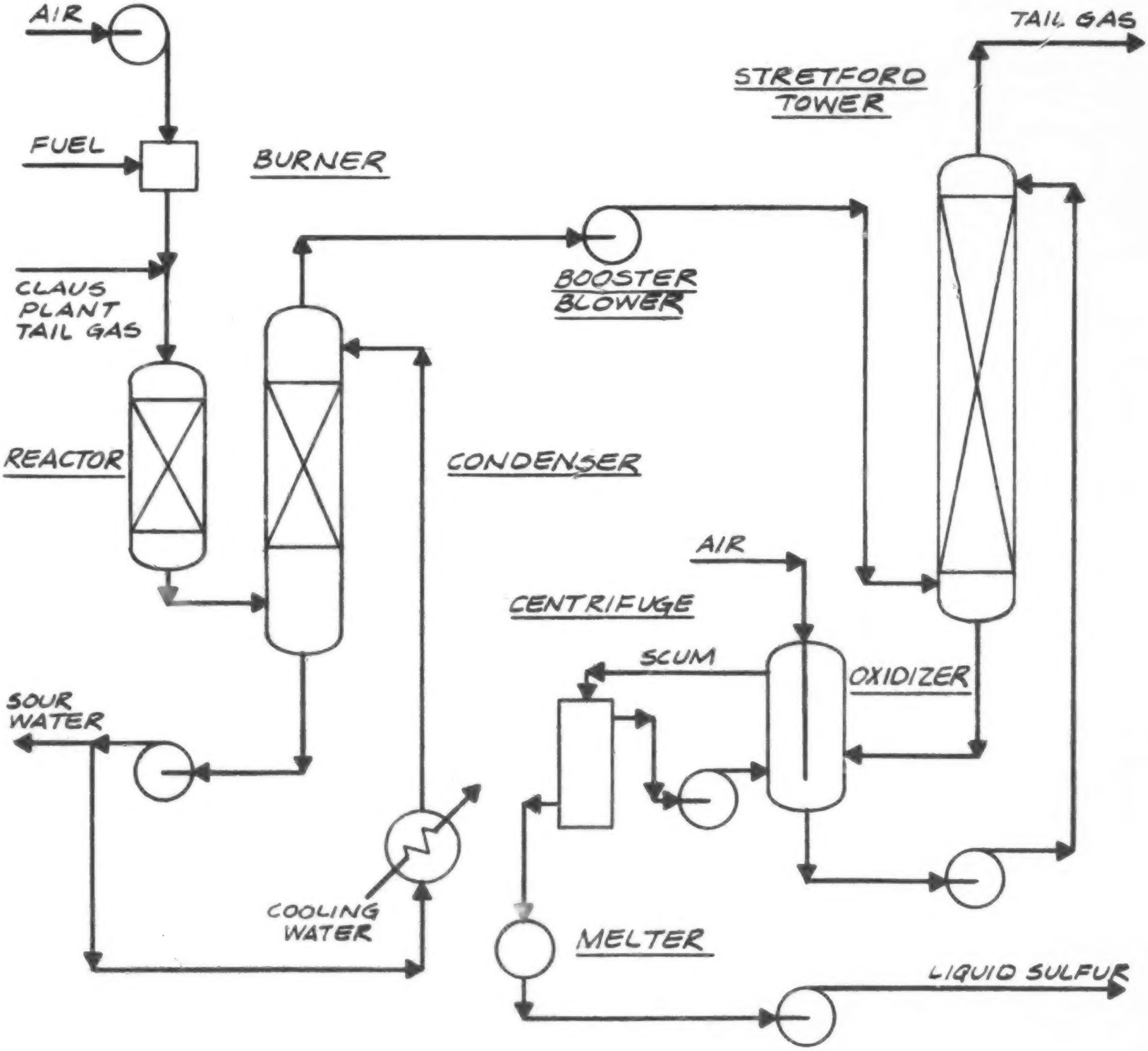
# APPENDIX J - THE RALPH M. PARSONS COMPANY INFORMATION

PR 109

Job EPA - OAP
Location UNITED STATES
Subject CLAUS PLANTS

**PROCESSES RESEARCH, INC.**
INDUSTRIAL PLANNING
AND RESEARCH
CINCINNATI NEW YORK

File No 03388 Sheet No J.1
Checked by ______ Date ______
Computed by WWB Date APRIL 1973


AIR
FUEL
BURNER
CLAUS
PLANT
TAIL GAS
REACTOR
CONDENSER
BOOSTER
BLOWER
STRETFORD
TOWER
TAIL GAS
AIR
CENTRIFUGE
SCUM
OXIDIZER
SOUR
WATER
COOLING
WATER
MELTER
LIQUID SULFUR

BEAVON SULFUR REMOVAL PROCESS

February 21, 1972

Mr. O. C. Rodday
Vice President, Precontract and Process
The Ralph M. Parsons Company
617 West Seventh Street
Los Angeles, California 90017

Subject: Claus Sulfur Units and Tail Gas Treatment

Dear Mr. Rodday:

Several of the methods being considered for abatement of sulfur emissions to the atmosphere include Claus sulfur units. The Environmental Protection Agency Office of Air Programs has engaged Processes Research, Inc., to study the efficacy of Claus sulfur plants in pollution abatement (Contract No. 68-02-0242).

We understand that your company is a prominent designer of Claus units worldwide and has developed, with Union Oil Company of California, a process for Claus tail gas pollution abatement. We are referring to your Beavon Sulfur Removal Process, described in the February 7, 1972, issue of The Oil and Gas Journal. Please let us have information available regarding typical Claus sulfur units and the Beavon process, as follows:

1. For typical Claus sulfur units, such as those based on natural gas (daily sulfur capacities of 10 tons, 100 tons, and 1000 tons, and gas feed concentrations of 15 mole percent, 50 mole percent, and 90 mole percent $H_2S$, and units having two and three Claus catalytic stages are of particular interest):

    a. Percentage sulfur recoveries and tail gas compositions for various acid gas feed concentrations and various numbers of catalytic stages.

    b. Variation of sulfur recovery during the usual life of the catalyst.

    c. Variation of sulfur recovery with acid gas feed at less than full capacity such as half of full feed rate.

    d. Approximate investment, royalty, catalyst costs, and consumption and generation of fuel, water, power and steam for various daily sulfur capacities, various acid gas feed concentrations and various numbers of Claus catalytic stages. (Do these include the acid gas recovery units, acid gas blowers, air blowers, and tail gas incinerators?).

e. Operator attendance requirements for various daily sulfur capacities, and number of days of operation to be expected annually.

2. For Beavon Sulfur Removal Process Units treating Claus tail gas (daily sulfur capacities of 1 ton, 10 tons and 100 tons, and Claus tail gas feed concentrations of 0.3 mole percent, 1 mole percent and 4 mole percent $H_2S + SO_2 + S + COS + CS_2$ are of particular interest):

   a. Approximate investment, royalty, catalyst costs, and consumption of fuel, water, power and steam for various daily sulfur capacities and various Claus tail gas feed concentrations. (Do these include the stripping of the $H_2S$ from the condensate?).

   b. Operator attendance and maintenance requirements.

   c. Percentage sulfur recoveries and off gas compositions for various Claus tail gas feed concentrations.

   d. Variation of sulfur recovery during the usual life of the catalyst.

   e. Is the quality of the sulfur recovered by the Beavon process equal to that of Claus sulfur?

   f. What, if any, air pollution is presented by entrainment of catalyst overhead from the Stretford tower? Is incineration of the off gas advisable?

   g. A principal cause of poor sulfur recovery in Claus plants is deviation from the optimum feed ratio of air to $H_2S$, resulting from inadequate instrumentation or careless operation. This also results in variations from the stoichiometric balance of $H_2S$ and $SO_2$ in the tail gas. Therefore, tail gases from Claus units having the greatest need for pollution abatement are likely to contain unbalanced and erratic quantities of $H_2S$ and $SO_2$. The Beavon process appears to be insensitive to such feed fluctuations. Do you concur in this observation?

   h. For a new Claus unit, should the Beavon process replace the third Claus stage? Should the Beavon process replace the Claus unit altogether?

   i. For an acid gas having an excessive ratio of $SO_2$ to $H_2S$, should the Beavon hydrogenation step be used to adjust the ratio for feeding the Claus unit? Is this more advantageous than catching the excess $SO_2$ in the Claus tail gas treatment?

We will appreciate receiving all of the above information which you can make available to us. Please let us know when we can expect to receive it.

We thank you for your cooperation.

Very truly yours,

PROCESSES RESEARCH, INC.

W. D. Beers
Project Manager

WDB:fj

cc: G. S. Haselberger
M. K. Jester
P. W. Spaite

The Ralph M. Parsons Company

*Engineers • Constructors*

617 WEST SEVENTH STREET, LOS ANGELES, CALIFORNIA

MAIL ADDRESS:
P. O. BOX 54802
LOS ANGELES 90054

March 23, 1972

Mr. W. D. Beers
Project Manager
Processes Research, Inc.
2912 Vernon Place
Cincinnati, Ohio 45219

SUBJECT: Claus Sulfur Units and Tail Gas Treatment
Your EPA Contract No. 68-02-0242

Dear Mr. Beers:

Thank you for your letter of February 21, 1972. We are pleased that you have come to us for assistance in this project; we have made every effort to be as complete as possible in preparing answers for your many questions.

For ease of reference we will follow your format as closely as possible in presenting our responses.

1. Claus Sulfur Units

(a) Depending upon the design of the sulfur plant and the nature of the impurities accompanying the feed $H_2S$, a considerable range of sulfur plant recoveries is possible. More or less in the middle of the range, it might be said that a 50 percent $H_2S$ feed gas would result in about 93 percent recovery from a well-designed Claus plant with two catalytic stages, or 95 percent with three catalytic stages. Similarly, a 90 percent $H_2S$ feed gas would yield about 94 percent recovery from a two-stage Claus unit or 96 percent from a three-stage unit. An $H_2S$ feed gas of only 15 percent purity requires a special design of the Claus plant and it is preferable not to generalize on the recovery from such a plant because the ratio of $H_2S$ to impurities such as hydrocarbons is so low that the recovery has to be estimated on a case-by-case basis. It is evident that the recovery from such a low purity $H_2S$ is low, and usually in the range of 80 per cent to 90 percent.

(b) It is customary to regenerate Claus plant catalyst after it has lost activity or become fouled. The life of the catalyst may range up to twelve years, with typically about one regeneration annually. After regeneration the catalyst should return to substantially its original activity, except for a permanent loss in activity for the hydrolysis of COS and $CS_2$ which may or may not be important in a particular plant. It is reasonable that catalyst would be discarded if regeneration fails to return it to within one or two percent recovery compared to its new performance. The frequency of regeneration, on the other hand, is very dependent upon local circumstances, including air pollution regulations. In some instances, a catalyst regeneration would occur with a loss of less than 1 percent in recovery; in other instances, the recovery might be allowed to slip as much as 10 percent before the catalyst is regenerated. Perhaps an overall industry average would find catalyst being regenerated after the yield has declined two or three percent.

(c) Turning down a sulfur plant to operate at less than full capacity usually causes a loss in percentage recovery; the amount of loss is highly dependent upon the design of the plant, and particularly depends on the method used for reheating the gases ahead of each Claus converter. With the method of reheat most often used by Parsons, a sulfur plant will typically lose two or three percent in recovery when turned down to 20 percent of design capacity.

(d) Approximate Investment

Includes royalty. Does not include acid gas recovery units or acid gas blowers. Does include air blowers, incinerators, and stacks.

| Gas Strength and Capacity | Investment - $MM | |
|---|---|---|
| | 2-stage | 3-stage |
| 90% $H_2S$ | | |
| 10 LT/D | 0.34 | 0.39 |
| 100 LT/D | 0.80 | 0.90 |
| 1,000 LT/D | 3.60 | 4.20 |

| Gas Strength and Capacity | Investment - $MM | |
|---|---|---|
| | 2-stage | 3-stage |
| 50% $H_2S$ | | |
| 10 LT/D | 0.37 | 0.43 |
| 100 LT/D | 0.90 | 1.05 |
| 1,000 LT/D | 4.10 | 4.90 |
| 15% $H_2S$ | | |
| 10 LT/D | 0.55 | 0.65 |
| 100 LT/D | 1.75 | 2.00 |
| 1,000 LT/D | 10.0 | 11.5 |

## Catalyst Cost

The typical cost of bauxite catalyst for a two-stage sulfur plant feeding 90 percent $H_2S$ is about $30 per daily long ton capacity. This cost would be increased by about 30 per cent for a 50 percent $H_2S$ feed gas. Adding a third Claus converter stage would increase the catalyst cost by 50 per cent. Using synthetic alumina catalyst would increase the cost by about 70 percent. Thus, the cost of catalyst for a three-stage sulfur plant feeding 50 percent $H_2S$ and using alumina catalyst would be about $100 per daily long ton capacity.

## Utilities Consumption

Using a 90 percent $H_2S$ feed gas as a basis for the production of one long ton per day of sulfur, the process would require about 0.6 gallons per minute of boiler feedwater. Electric power is needed only for lighting and miscellaneous purposes, since the air blower is driven by steam produced in the process at 150 psig pressure and exhausted at 50 psig. Fuel gas is needed for start-up and regeneration only. Net production of useable steam is 140 lbs. per hour at 150 psig and 140 lbs. per hour at 50 psig. The incinerator is excluded from the above statements. The above steam quantities may be used with reasonable accuracy for 50 percent $H_2S$ feed gas, and they are essentially independent of plant size.

(e) Operator Attendance and On-stream Factor

Sulfur plants up to about 100 LT/D capacity usually require the attendance by a man about 20 percent of the time. This depends of course on the location of the plant, degree of instrumentation, and other factors. Larger plants will tend to require somewhat more attention.

A Parsons sulfur plant typically has an on-stream factor in excess of 95 percent.

2. Beavon Sulfur Removal Process Units

As a general comment, we have never seen a Claus tail gas containing as little as 0.3 mol percent of ($H_2S + SO_2 + S + COS + CS_2$); this includes the tail gas issuing from the IFP and Sulfreen tail gas processes. Our remarks are therefore directed to tail gases containing either one or four mol percent equivalent $H_2S$.

(a) Approximate Investment

Includes royalty. Our current design does not require condensate stripping. Sulfur produced in molten form.

| Total Sulfur Content and Capacity | Investment - $MM |
|---|---|
| 1.0% S Equivalent | |
| 1 LT/D | 0.69 |
| 10 LT/D | 1.40 |
| 100 LT/D | 5.80 * |

* Multiple hydrogenation and Stretford trains

| Total Sulfur Content and Capacity | Investment - $MM |
|---|---|
| 4.0% S Equivalent | |
| 1 LT/D | 0.61 |
| 10 LT/D | 1.20 |
| 100 LT/D | 3.50 ** |

** Multiple Stretford trains

Catalyst Cost

The cost of a catalyst fill is approximately $70 per daily long ton of Claus plant capacity. The catalyst is expected to have a three-year life.

Utilities Consumption

Utilities consumption is as follows:

| | Quantity | Basis |
|---|---|---|
| Fuel gas | 1.25 MSCFD | per daily ton parent sulfur plant capacity |
| 50# steam (produced) | 25 #/Hr | per daily ton parent sulfur plant capacity |
| Power | 85 HP | per ton sulfur in tail gas |
| Soft water | 2,500 gal. | per ton sulfur in tail gas |
| Chemicals | $8 | per ton sulfur in tail gas |

The foregoing utility figures apply to an advanced version of the flow scheme in which condensate is not produced as such and therefore stripping of the $H_2S$ from it is obviated.

(b) Operator Attendance

For all but very large plants the attendance of an operator is required between 25 percent and 50 percent of his time.

Maintenance requirements are expected to be modest. Operating temperatures and pressure are comparatively low and no inherently corrosive or erosive conditions prevail. Materials of construction are essentially all carbon steel, with epoxy coatings in several areas.

(c) Recoveries and Tail Gas Compositions

Tail gas containing about four percent equivalent $H_2S$ contains less than 80 ppm equivalent $SO_2$ after treatment, with COS constituting the major part of the combined sulfur and with $H_2S$ contributing less than 1 ppm. Treatment of a tail gas containing 1 percent equivalent $H_2S$ is expected to yield a final tail gas containing less than 40 ppm equivalent $SO_2$.

(d) Variation in Recovery

No detectable variation of sulfur recovery is expected over a one-year period between catalyst regenerations.

(e) Sulfur Quality

The sulfur recovered by the Beavon process is expected to be somewhat better than 99.8 percent pure, while Claus sulfur usually is at least 99.98 percent pure. Either the Beavon process sulfur or the mixture of it with Claus sulfur meets all usual specifications for commercial sulfur.

(f) Stretford Entrainment

Entrainment of catalyst overhead from the Stretford tower is avoided by proper design of the tower internals, and the vent gas stream is expected to meet all known air pollution standards. Incineration of the off gas may be practised, but in our opinion it is unnecessary and inadvisable because of the substantial cost for fuel if an incinerator is operated.

(g) Process Sensitivity

Because of broad experience in the design and construction of many refineries and more than 160 Claus plants, The Ralph M. Parsons Company is well aware that the sulfur plant is at the very end of the train of refinery processes, and is subject to continual disturbance because of variations in the up-stream units. These variations make it very difficult to control a refinery sulfur plant with an exact stoichiometric balance of $H_2S$ to $SO_2$. A prime requisite in the development of our process was that it be essentially immune to upsets caused by such variations. This immunity is brought about by the fact that an excess of hydrogen is at all times available to drive the desired reactions to completion, and this excess of hydrogen may be emitted to the atmosphere without causing air pollution. In many months of pilot unit testing on the tail gas of commercial sulfur plants, in both oil refinery and natural gas treating installations, we have found that the process is indeed virtually immune to any problems resulting from such fluctuations. The tail gas is always purified, and the worst result we have observed is a very small consumption of alkali when the parent sulfur plant was extremely upset and insufficient hydrogen was available. This insufficiency resulted only from the fact that no analytical instrument was available on the pilot unit to give warning; analytical instruments will, of course, be provided on commercial units.

We concur in your observation that the Beavon process is insensitive to feed fluctuations.

(h) For a new Claus unit the Beavon process probably should replace the third Claus stage in all but very large units (probably larger than about 500 LT/D).

Using the Beavon process to replace the Claus unit altogether may be desirable in small size plants with feed gas free of certain impurities.

(i) We understand your question to apply to a Claus unit being fed with a mixture of $H_2S$ and $SO_2$, containing excess $SO_2$. If the excess of $SO_2$ is substantial, a slight modification in the design of the Claus unit may be used to adjust the ratio so that the Claus unit is more efficient and less sulfur remains to be taken out when the tail gas is treated. For economic reasons, this is preferable. However, the Beavon hydrogenation step can indeed be used to overcome any reasonable excess of $SO_2$ in the Claus tail gas, and the only argument against handling the excess $SO_2$ in this way is the relatively higher cost of making sulfur in the Stretford unit compared to the cost of making it in the Claus plant.

We trust that we have adequately responded to your needs. Should any clarification be required, we shall of course be pleased to hear from you.

Very truly yours,

THE RALPH M. PARSONS COMPANY

By O C Roddey
O. C. Roddey
Vice President

OCR:ro

# APPENDIX K - J. F. PRITCHARD & CO. INFORMATION

February 22, 1972

Mr. D. F. Cole
J. F. Pritchard and Company
4625 Roanoke Parkway
Kansas City, Missouri 64112

Subject: Claus Sulfur Units and Tail Gas Treatment

Dear Mr. Cole:

Several of the methods being considered for abatement of sulfur emission to the atmosphere include Claus sulfur units. The Environmental Protection Agency Office of Air Programs has engaged Processes Research, Inc., to study the efficacy of Claus sulfur plants in pollution abatement (Contract No. 68-02-0242).

We understand that your company designs Claus units and has developed, with Texas Gulf Sulfur Company and the British Northwestern Gas Board, a process for Claus tail gas pollution abatement. We are referring to the Cleanair Process described in the February 7, 1972, issues of Chemical Engineering and The Oil and Gas Journal. Please let us have information available regarding typical Claus sulfur units and the Cleanair Process, as follows:

1. For typical Claus sulfur units, such as those based on natural gas (units having daily sulfur capacities of 10 tons, 100 tons, and 1000 tons, acid gas feed concentrations of 15 mole percent, 50 mole percent, and 90 mole percent $H_2S$, and two and three Claus catalytic stages are of particular interest):

    a. Percentage sulfur recoveries and tail gas compositions, before incineration, for various acid gas feed concentrations and various numbers of catalytic stages.

    b. Variation of sulfur recovery during the usual life of the catalyst.

    c. Variation of sulfur recovery with acid gas feed at less than full capacity, such as half of full feed rate.

    d. Approximate investment, royalty, catalyst costs, and consumption and generation of fuel, water, power and steam for various daily sulfur capacities and various acid gas feed concentrations. (Please exclude the acid gas recovery units, but include the air blowers and tail gas incinerators.)

e. Operator attendance, maintenance, and catalyst replacement requirements for various daily sulfur capacities. Number of days of operation to be expected annually.

f. What acid gas feed pressure is required to avoid need for repressurization to incinerate the tail gas?

2. For Cleanair units treating Claus tail gas to reduce the sulfurous content to less than 300 ppm by volume $SO_2$ equivalent, before incineration (please include the range of Claus tail gas feed rates and compositions produced by the Claus units previously described; we understand that Claus units designed by others or using other catalysts may produce different tail gases affecting the costs of suitable Cleanair units):

   a. Flow diagram.

   b. Approximate investment, royalty, catalyst costs, and consumption of fuel, water, power and steam for various daily sulfur capacities and various Claus tail gas feed concentrations, assuming that the feed gas is at atmospheric pressure.

   c. Operator attendance, maintenance, and catalyst replacement requirements for various daily sulfur capacities. Number of days of operation to be expected annually.

   d. Percentage sulfur recoveries for various Claus tail gas feed concentrations. Variation of sulfur recovery during the usual life of the catalyst, and for various ratios of $H_2S$ to $SO_2$ in the Claus tail gas feed.

   e. What is the form of the recovered sulfur? Is the recovered sulfurous stream recycled to the Claus unit? What, if any, impurities occur in the sulfur recovered by the Cleanair Process, other than those occurring in the Claus sulfur?

   f. What, if any, air pollution is presented by entrainment of catalyst or solvent in the off gas from the Cleanair unit? Is incineration of the Cleanair off gas advisable?

3. For new sulfur plants based on natural gas, combining Claus units and Cleanair units to reduce the sulfurous content of the tail gas to less than 300 ppm by volume $SO_2$ equivalent, before incineration (plants having daily sulfur capacities of 10 tons, 100 tons, and 1000 tons, and acid gas concentrations of 15 mole percent, 50 mole percent, and 90 mole percent $H_2S$. are of particular interest):

   a. Flow diagram.

b. Percentage sulfur recoveries and off gas compositions, before incineration, for various acid gas feed concentrations.

c. Variation of sulfur recovery during the usual life of the catalysts.

d. Variation of sulfur recovery with acid gas feed at less than full capacity, such as half of full feed rate.

e. Approximate investment, royalty, catalyst costs and consumption and generation of fuel, water, power and steam fof various daily sulfur capacities and various acid gas feed concentrations. (Please exclude the acid gas recovery units, but include the air blowers, and, if advisable, include the off gas incineration.)

f. Operator attendance, maintenance, and catalyst replacement requirements for various daily sulfur capacities. Number of days of operation to be expected annually.

g. What acid gas feed pressure is required, including, if advisable, the off gas incineration?

We will appreciate receiving all of the above information which you can make available to us. Please let us know when we may expect to receive it.

We thank you for your cooperation.

Very truly yours,

PROCESSES RESEARCH, INC.

W. D. Beers
Project Manager

WDB:fj

cc: C. S. Haselberger
M. R. Jester
P. W. Spaite

**J. F. PRITCHARD & CO.**
ENGINEERS - CONSTRUCTORS
4625 ROANOKE PARKWAY
KANSAS CITY, MISSOURI 64112
TWX 910 771 2102
TELEPHONE (816) 531-9500
CABLE PRICO

June 5, 1972

Mr. W. D. Beers
Project Manager
Process Research Incorporated
2912 Vernon Place
Cincinnati, Ohio

SUBJECT: CLAUS SULPHUR PLANTS & TAIL GAS TREATMENT

Dear Mr. Beers:

We are pleased to respond to your request for information concerning Claus Sulphur Plants and Pritchard's CLEANAIR Sulphur Process for treating Claus tail gas. The information presented should assist in your study for the Environmental Protection Agency Office of Air Programs.

## PRITCHARD EXPERIENCE

Pritchard has a wealth of experience in gas treating and sulphur recovery. We have built over 50 Amine plants, 16 Sulphur Recovery Plants ranging in size from 10 LT/D to 1500 LT/D. We currently have contracts for 3 CLEANAIR Sulphur Plants. In addition, we have built or are designing eight Stretford Sulphur Recovery units. The enclosed Stretford and CLEANAIR brochures describe these two processes and present the extent of technical information that we are at liberty to discuss without appropriate Secrecy Agreements.

## CAPITAL COSTS AND UTILITY REQUIREMENTS

Presented in the attached Tables, listed below, are order-of-magnitude capital costs and utility requirements for the three cases cited in your inquiry letter. The information is presented for sulphur recovery units of 10, 100, 500 and 1000 LT/D.

Table I - Description of Cases Studied
Table II - Order-of-Magnitude Capital Costs
Table III - Utility Basis
Table IV - Order-of-Magnitude Utilities

## PERFORMANCE OF UNITS

New Claus plants are generally designed for recoveries of 95% plus. It is not uncommon for Pritchard to guarantee 96% recovery when fed with Amine off gas having an $H_2S$ concentration between 50% and 90%. Nearly all new units are being designed with three Claus reactors.

When a CLEANAIR Sulphur plant is added to an existing Claus unit or built concurrently and incorporated in a new Claus unit, the CLEANAIR plant effluent is normally guaranteed to contain less than 250 to 300 ppm (vol.) of equivalent sulphur dioxide on an undiluted basis. The sulphur recovered is bright yellow, 99.9% pure, saleable sulphur. There is no entrainment of catalyst of solvent in the effluent gas from the CLEANAIR unit. It is normally not required or recommended that CLEANAIR effluent be incinerated, as this presents a possible source of NOX formation.

## PROCESS QUESTIONS

### (1) Variation of Sulphur Recovery

Sulphur recovery in Pritchard Claus plants will normally drop 1 to 2%, say from 96 to 94% over the period of Catalyst life. Catalyst life will generally vary from 2 to 5 years depending on how the plant has been operated and, of course, the feedstock. High concentrations of heavy hydrocarbons ($C_5$+) will cause carburization of the catalyst and shorten the life. High $CO_2$ concentrations will also affect life.

The CLEANAIR Sulphur plant provides extreme flexibility in handling varying and decreasing amounts of sulphur constituents in the Claus tail gas. These plants can be designed to operate on tail gases, varying threefold in sulphur constituents. The $H_2S$ to $SO_2$ ratio in the tail gas can vary up to 8:1 without sacrifice in effluent quality.

### (2) Turndown

Claus plants can be designed (and are operating) with turndown capability of 33% without sacrifice in sulphur recovery.

The CLEANAIR plant will operate from 0% to 100% of design without sacrifice in effluent quality or increasing operator attention.

(3) Pressure Drop

Acid gas feed pressures of 6 to 10 psig are adequate to avoid repressurization to incinerate the tail gas. If a CLEANAIR unit is added to an existing Claus unit it is often necessary to add a booster blower to overcome the small pressure drop in the CLEANAIR unit. This capability is built in the Claus blower for integrated Claus-CLEANAIR units.

MAINTENANCE AND OPERATIONS

Claus plants generally operate 365 days per year. Their shutdown periods are generally dictated by local boiler inspection requirements. Some Claus units have run as long as 5 years without shutdowns. CLEANAIR units will operate as long, if not longer, than Claus units without shutdown.

The estimated manpower requirements for inside battery limits units are shown in Table IV.

Catalyst replacement will vary from 2 to 5 years.

We thank you for the opportunity to participate in your study and request a copy of your final report when completed. We hope this information meets your needs.

Very truly yours,

J. F. PRITCHARD & COMPANY

Cole 6/6/72
D. F. Cole
Contract Engineer

DFC:ja
Enclosures

cc: George Thomas - Process Research

## TABLE I

## DESCRIPTION OF CASES STUDIED

The following Table II presents order-of-magnitude total installed capital costs for three separate types of sulphur recovery units. A summary of the estimating basis is described below:

### CASE A: CLAUS UNIT

The estimates presented are based on historical data from the more than 15 Claus plants built by Pritchard ranging in capacity from 10 LT/D to 1500 LT/D. In general, if the $H_2S$ in the feed gas is in excess of 50%, the investment cost will generally follow a pattern based on recovery size in LT/D. These costs are based on 3 Claus reactors, $H_2S$ feed % between 50 and 90% and assume a recovery of 95%, although some units were actually guaranteed at 96% recovery. The costs shown include the following:

- Battery Limits Plant
- Incinerator and Stack
- Sulphur Pit (1 week) and Loading Pumps
- Paid up Royalty
- Initial Charge of Catalyst

### CASE B: CLEANAIR SULPHUR PLANT

The estimates are based on actual contracts or firm price estimates previously prepared. The costs assume the CLEANAIR unit is added to an existing Claus unit operating at 95% recovery. The CLEANAIR unit produces an effluent gas containing less than 300 ppm (vol.) of equivalent $SO_2$ without dilution. The CLEANAIR costs shown include the following:

- Battery Limits Plant
- Paid up Royalty
- Initial Charge of Catalyst and Chemicals

### CASE C: INTEGRATED CLAUS CLEANAIR PLANT

This case represents a new installation with a Claus plant and CLEANAIR plant built together, in which case Stage III is incorporated in the Claus plant and overall Claus recovery is no less than 96%. Stages I & II treat the Claus tail gas producing an effluent with less than 300 ppm (vol.) of equivalent $SO_2$ without dilution. The costs shown include:

- Battery Limits Plant
- Sulphur Pit (1 week) & Loading Pumps
- Paid up Royalties
- Initial Charge of Catalyst & Chemicals

## TABLE II

## ORDER OF MAGNITUDE CAPITAL COSTS

| TYPE OF UNIT | CLAUS UNIT SIZE LT/D (1) | ORDER-OF-MAGNITUDE INSTALLED COST |
|---|---|---|
| CASE A | | |
| Claus Unit with 3 Stage Conversion | 10 | $300,000 |
| | 100 | $1,000,000 |
| | 500 | $3,000,000 |
| | 1,000 | $4,800,000 |
| CASE B | | |
| CLEANAIR SULPHUR Plant on Existing Claus Unit | 10 (0.5) (2) | $600,000 |
| | 100 (5) (2) | $1,400,000 |
| | 500 (25) (2) | $2,700,000 |
| | 1,000 (50) (2) | $3,400,000 |
| CASE C | | |
| Claus-CLEANAIR Integrated Unit New Installation | 10 | $800,000 |
| | 100 | $2,100,000 |
| | 500 | $5,200,000 |
| | 1,000 | $7,700,000 |

NOTES

(1) Size of unit is actual sulphur in feed gas
(2) Figures in parenthesis represent actual sulphur recovered in the CLEANAIR unit with a Claus unit operating at 95% recovery.

June 5, 1972

## TABLE III

## UTILITY BASIS

| | |
|---|---|
| Boiler Feed Water | 220° F, 60 psig |
| Steam | 50 psig |
| Cooling Water | 80° F, 30 psig, 15° F Rise |
| Electricity | 460 V/3 phase/ 60 $h_3$ |
| Fuel Gas | 900 BTU/SCF @ 40 psig |

## TABLE IV SHEET 1 of 2

## ORDER OF MAGNITUDE UTILITIES(1)

| | BFW LB/HR | STEAM LB/HR | COOLING WATER GPM | ELECTRICITY KW |
|---|---|---|---|---|
| **CASE A: CLAUS** | | | | |
| Recovery LT/D | | | | |
| 10 | 3000 | (2,800) | — | 40 |
| 100 | 27,000 | (26,000) | — | 350 |
| 500 | 130,000 | (126,000) | — | 1750 |
| 1000 | 250,000 | (240,000) | — | 3500 |
| **CASE B: CLEANAIR** | | | | |
| Recovery LT/D | | | | |
| 10 (0.5) | — | 80 | 100 | 50 |
| 100 (5) | — | 800 | 900 | 380 |
| 500 (25) | — | 4000 | 4550 | 1900 |
| 1000 (50) | — | 8000 | 9100 | 3800 |
| **CASE C: CLAUS-CLEANAIR** | | | | |
| Recovery LT/D | | | | |
| 10 | 3000 | (2700) | 100 | 90 |
| 100 | 27000 | (25000) | 900 | 730 |
| 500 | 130,000 | (122,000) | 4550 | 3650 |
| 1000 | 250,000 | (232,000) | 9100 | 7300 |

(1) Based on Utilities Supplied Per Table III

June 5, 1972

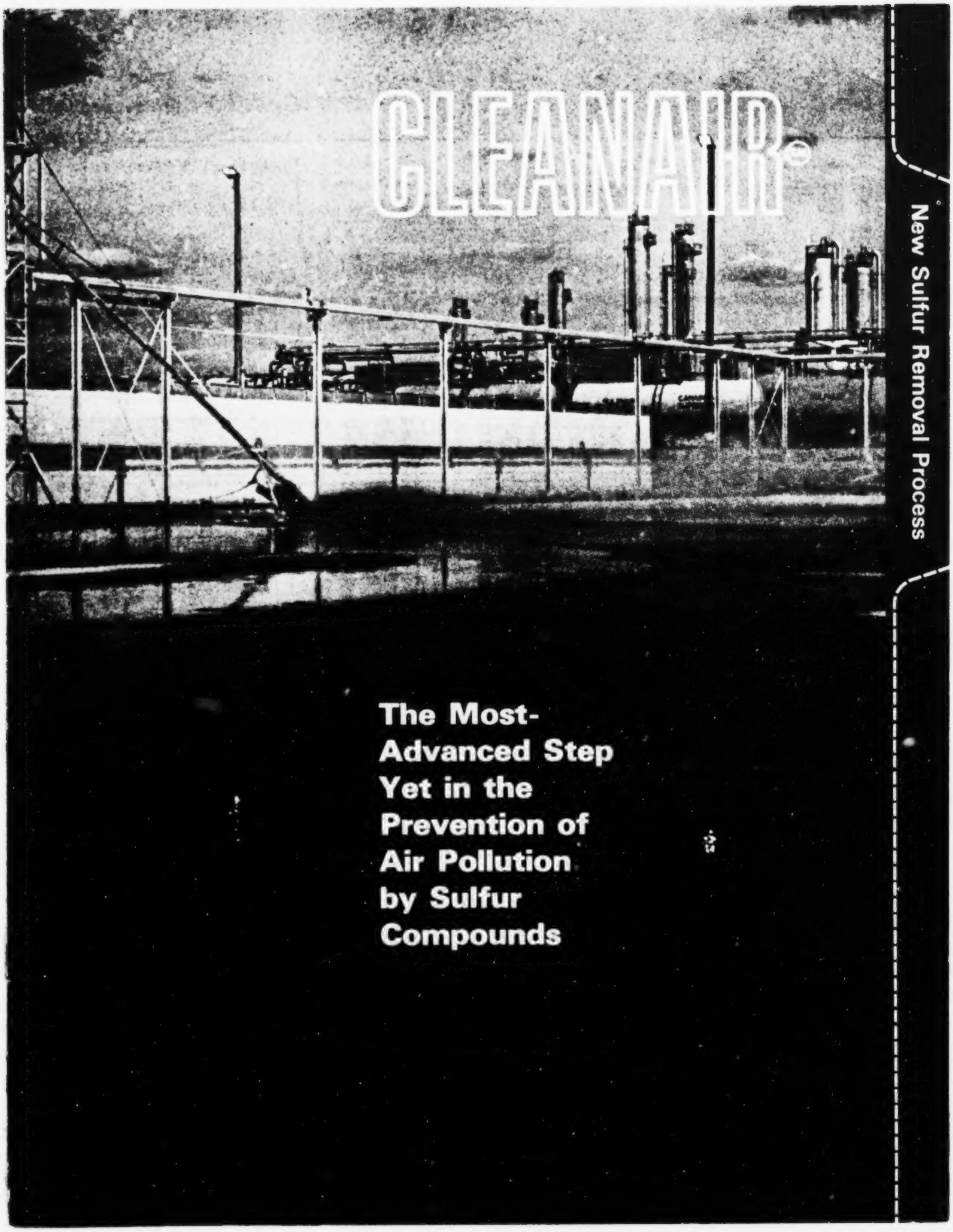
TABLE IV SHEET 2 OF 2

## ORDER OF MAGNITUDE UTILITIES (1)

| | FUEL GAS SCFH | CHEMICALS $/DAY | MAN POWER MEN/SHIFT |
|---|---|---|---|
| **CASE A: CLAUS** | | | |
| Recovery LT/D | | | |
| 10 | 200 | — | ½ |
| 100 | 2000 | — | ½ |
| 500 | 7500 | — | 1 |
| 1000 | 15000 | — | 1½ |
| **CASE B: CLEANAIR** | | | |
| Recovery LT/D | | | |
| 10 (0.5) | 100 | 1 | ¼ |
| 100 (5) | 900 | 9 | ¼ |
| 500 (25) | 4500 | 45 | ⅓ |
| 1000 (50) | 9000 | 90 | ½ |
| **CASE C: CLAUS-CLEANAIR** | | | |
| Recovery LT/D | | | |
| 10 | — | 1 | 3/4 |
| 100 | — | 9 | 3/4 |
| 500 | — | 45 | 1 |
| 1000 | — | 90 | 1 3/4 |

(1) Based on Utilities Supplied Per Table III

June 6, 1972

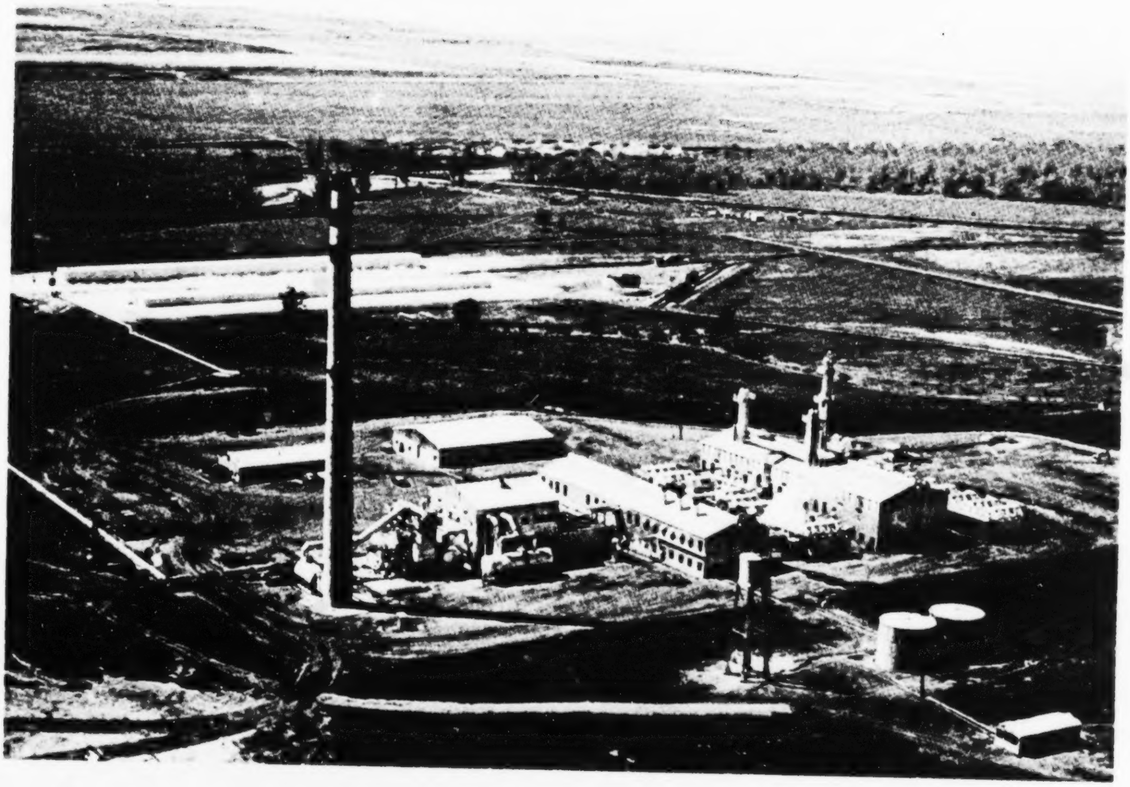


# CLEANAIR®

New Sulfur Removal Process

The Most-
Advanced Step
Yet in the
Prevention of
Air Pollution
by Sulfur
Compounds

# ...was proven here!



The pilot testing and development work for the "CLEANAIR" Sulphur Process was carried on jointly by J. F. Pritchard and Company, and Texas Gulf Sulphur Company, operator of the plant at Okotoks, near Calgary, Alberta, Canada (shown here). This significant new technology can result in cleaning up stack gas emissions from sulfur plants to less than 250 ppmv equivalent $SO_2$.

Pritchard's new CLEANAIR Sulphur Process offers the next step in sulfur recovery beyond Claus-type systems. The technology includes the very successful Stretford process, plus two new processes developed and pilot tested by Pritchard and Texas Gulf Sulphur Company.

# ...THE MOST ADVANCED STEP

**in the prevention of air pollution by sulfur compounds; 99.9% sulfur recovery, leaving less than 250 ppmv equivalent $SO_2$ in the effluent.**

**99.9% REMOVAL GUARANTEED!**

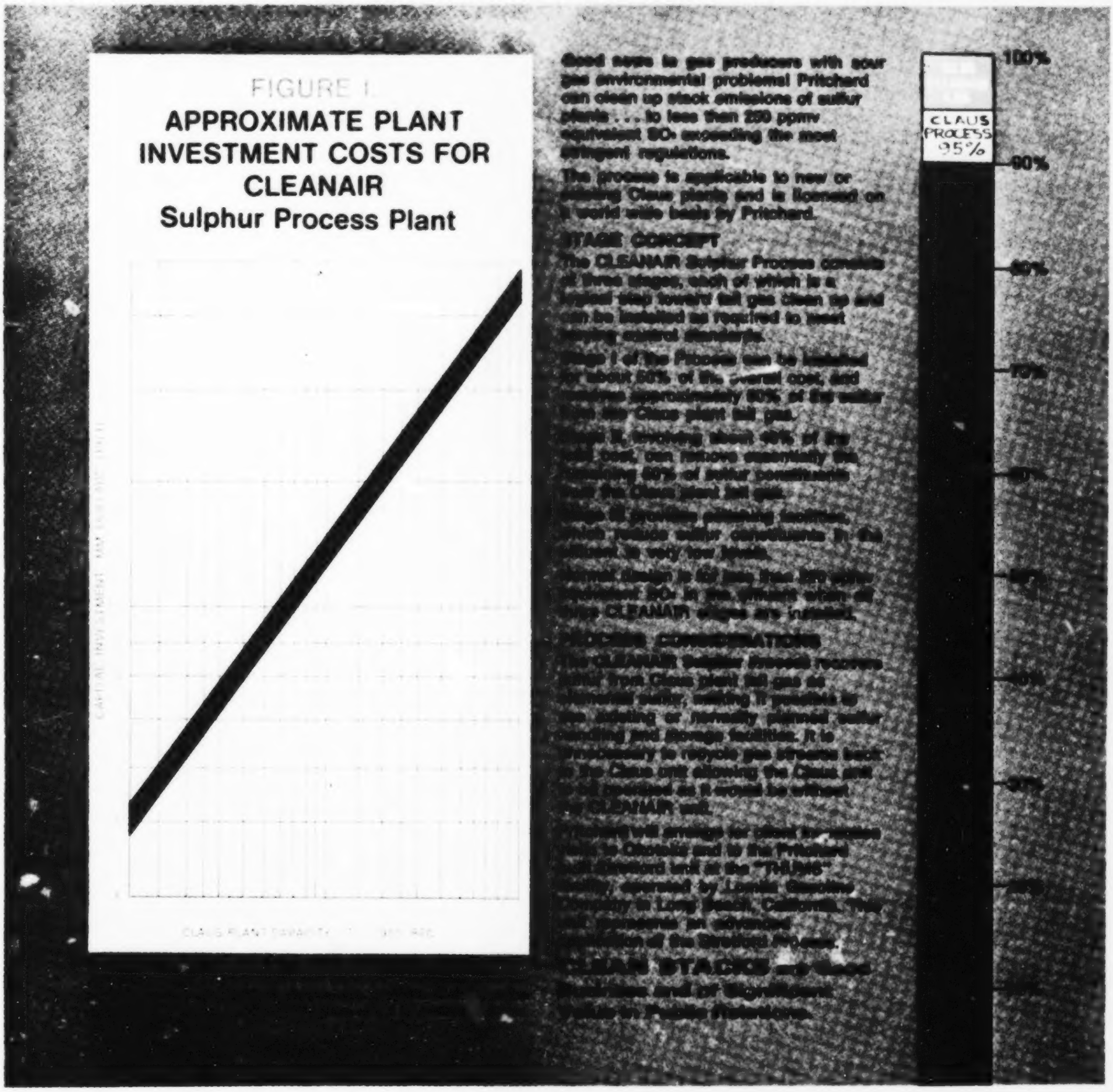


FIGURE I.

APPROXIMATE PLANT INVESTMENT COSTS FOR CLEANAIR Sulphur Process Plant

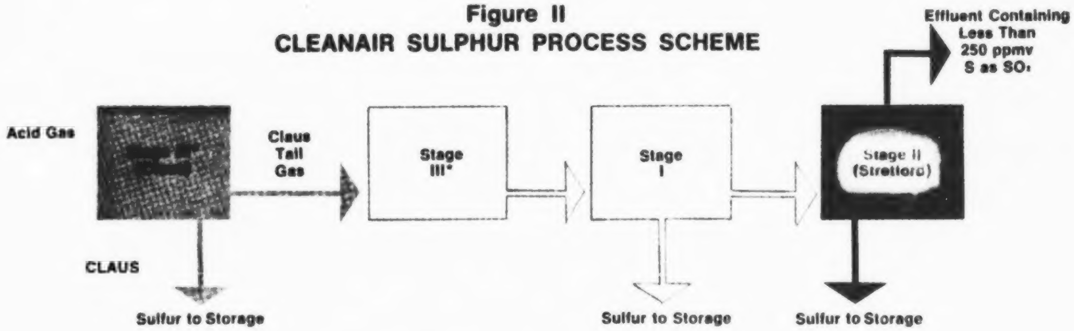
Good news to gas producers with sour gas environmental problems! Pritchard can clean up stack emissions of sulfur plants . . . to less than 250 ppmv equivalent $SO_2$ exceeding the most stringent regulations.

The process is applicable to new or existing Claus plants and is licensed on a world wide basis by Pritchard.

**STAGE CONCEPT**

The CLEANAIR Sulphur Process consists of three stages, each of which is a logical step toward tail gas clean up and can be installed as required to meet varying control standards.

## Figure II
## CLEANAIR SULPHUR PROCESS SCHEME



*Stage III is incorporated into new Claus plant designs while it operates on tail gas in existing units

**Table I**

| Stage | Approx. % of Investment | Recovery of S in Tail Gas | Function |
|---|---|---|---|
| I | 50 | Approx. 50 | Converts essentially all of the $SO_2$ to S with some conversion of $H_2S$ to S. |
| II | 40 | Approx. 50 | Converts remaining $H_2S$ to S. |
| III | 10 | Polishes effluent to less than 250 ppmv equivalent $SO_2$ | Reduces COS and $CS_2$ level in tail gas. |

Development work has been carried out on a semi-commercial scale at the 400 LT/D Okotoks plant of which Texas Gulf Sulphur Company is the operator. Actual plant streams from an operating commercial Claus plant are processed in the pilot plant facilities. The stream quantities processed are equivalent to a 4 to 5 LT/D Claus unit. Pilot facilities have been in operation since 1968.

The pilot plant program had two main objectives:

- *Tail gas clean-up for existing Claus units.*
- *Design and clean-up of new Claus installations.*

Technology exists to meet the stringent requirements established by pollution authorities. Sulfur recovery could be increased by the addition of third and even fourth stages of Claus conversion—but there are limits. Conversion efficiency is limited by chemical equilibrium, particularly as dictated by temperature and the presence of water. The amount of additional sulfur recovered decreases while the recovery cost of the incremental sulfur skyrockets. Lowering the temperature or removing water favorably affects conversion, but results in solidification of sulfur. Consequently, 98% recovery is the maximum for Claus processing—far from acceptable by the standards being implemented today.

Indeed, some standards are so rigid that they require removal of organic sulfur compounds, carbonyl sulfide (COS) and carbon disulfide ($CS_2$), that are present in Claus plant tail gas streams in addition to hydrogen sulfide and sulfur dioxide. Previously, removal of COS and $CS_2$ has received little emphasis since the quantities involved had minor effect on overall sulfur recovery. Consequently, the state of the art with respect to removal of these compounds has been less fully developed than the knowledge involved in the removal of $H_2S$ and $SO_2$.

Pritchard has engineered and built Claus plants since 1953 including units ranging in size from 10 to 1,500 tons of sulfur per day. This experience plus recent Okotoks development work has defined the troublesome areas in tail gas clean-up and has established design parameters for new Claus plants to minimize these problems.

Pritchard, as a result of the CLEANAIR Sulphur Process development, can offer to industry the technology required to meet existing and anticipated environmental standards. By combining an established process with proven sulfur chemistry and catalyst developments, Pritchard provides process know-how to advance the state-of-the-art in sulfur recovery. As a result of development work and engineering/construction expertise, Pritchard will custom design plants to meet individual client requirements.

## $SO_2$ Conversion (Stage I)

J. F. Pritchard and Company joined with Texas Gulf Sulphur Company to continue a development project initiated by TGS some two years earlier. The objective of this development work was to convert $SO_2$ in Claus unit tail gas to sulfur. The result of the joint effort is Stage I of the CLEANAIR Sulphur Process.

The pilot plant has consistently demonstrated removal of $SO_2$ down to 75 ppmv. Commercial design is for 100 ppmv. Some $H_2S$ is converted to sulfur in Stage I. All of the entrained elemental sulfur is recovered also.

## $H_2S$ Conversion (Stage II)

## The Stretford Process

The CLEANAIR system employs the Stretford Process as Stage II. The Stretford Process, a development of the North Western Gas Board of England, is offered by Pritchard through license. There are more than 50 units in commercial operation throughout the world. Pritchard built and successfully commissioned the first Stretford unit in the United States for THUMS Long Beach Company and the Department of Oil Properties in Long Beach, California. In addition, Pritchard is now engineering and constructing additional Stretford units for clients in North America.

The Stretford Process consists of a gas washing system wherein the gas is contacted countercurrently with an alkaline washing solution. Hydrogen sulfide is removed from the gas stream and oxidized to solid sulfur. The sulfur is formed as a finely dispersed solid in the circulating solution. The reduced solution is then oxidized by air blowing which simultaneously removes the sulfur by froth flotation. Oxidized solution is returned to the gas washing system to repeat the cycle.

## $COS/CS_2$ Removal (Stage III)

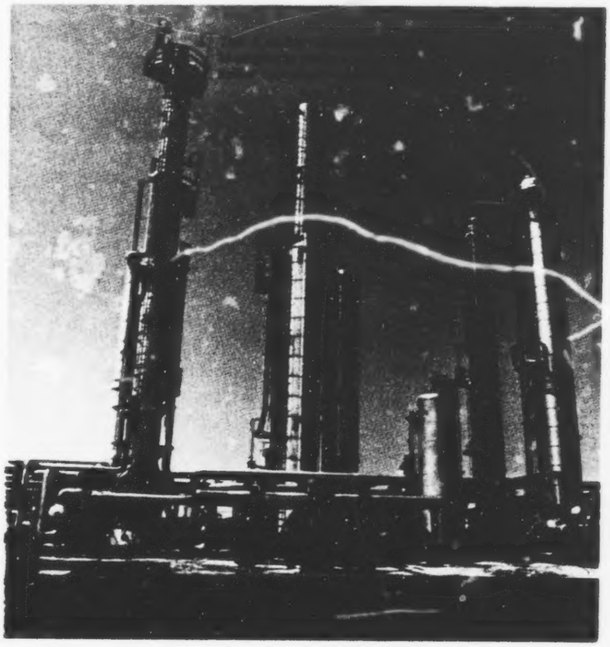
## An Industry Breakthrough

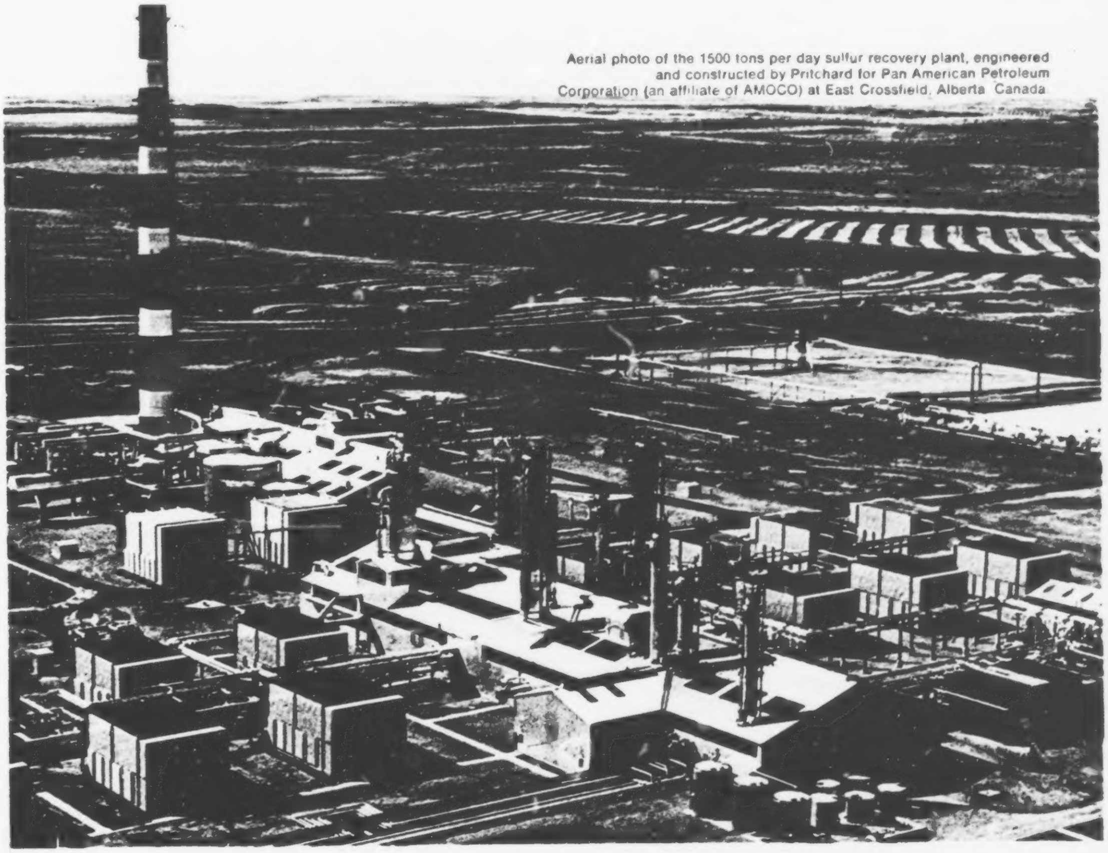
Some of the sulfur components in a Claus unit acid gas feed, which contains carbon dioxide and a minute quantity of light hydrocarbons, are converted to COS and $CS_2$ in the Claus reaction unit. As much as 25% of the sulfur present in the tail gas may be in the form of these organic sulfur components. Equivalent $SO_2$ concentration varies from 4,000 ppmv for a Claus unit operating at 96% sulfur recovery to 10,000 ppmv for a unit operating at 90% recovery.

Obviously COS and $CS_2$ removal must be accomplished to meet proposed standards that limit total sulfur emissions to 250 ppmv. The CLEANAIR Sulphur Process incorporates such removal as Stage III.

COS and $CS_2$ formation in Claus units has been correlated as a function of acid gas composition. The correlations are based on data from operating plants. The correlations have been substantiated through pilot plant work and are used in predicting COS and $CS_2$ formation in the design of Claus plants.

Stage III of the Process was developed through 18 months of pilot plant operation. COS and $CS_2$ contamination has consistently been lowered from 12,000 ppmv to 150 ppmv. In the pilot unit, investigations have been performed on process streams from several points in the Claus process to determine the most economical means of accomplishing COS and





Aerial photo of the 1500 tons per day sulfur recovery plant, engineered and constructed by Pritchard for Pan American Petroleum Corporation (an affiliate of AMOCO) at East Crossfield, Alberta, Canada.

$CS_2$ conversion. The results of these investigations are incorporated into the design of new Claus units as well as CLEANAIR units for tail gas treatment on existing Claus plants.

## Reliability

The CLEANAIR Sulphur Process is carefully designed to assure reliability and ease of operation. It is expected that codes will not allow periods of variance of emission standards. Testing has been carried out to determine proper materials of construction. Critical items of equipment are spared to allow continuous operation.

As an example of the CLEANAIR flexibility, the Stretford solution (Stage II) can be overloaded by $H_2S$ as much as 100% with only minor changes in normal operating procedures. This feature is especially important when it becomes necessary to burn off catalyst in a Claus unit. This also allows Stage I to be taken out of service while Stages II and III continue to operate. This flexibility permits the plant to meet continuous on-stream demands for clean-up systems.

FORM CASP 5M 7112

The CLEANAIR unit can be turned down to any rate below design without difficulty, and can even be idled on line. In cases such as oil refineries, where a number of units produce acid gas, normal shutdown of individual units causes feed rates to the Claus unit to vary. Ordinarily, Claus units operate at lower recovery efficiencies when fed at lower than design rates. The CLEANAIR unit, while designed for clean-up at full Claus plant rate, also guarantees total recovery over the full range of Claus plant operability.

## Product Sulfur Quality

Sulfur produced in a CLEANAIR unit is typically 99.5% pure, but Pritchard can guarantee the sulfur product to be 99.9% pure based on total pit production. The sulfur is suitable for any ultimate use. A typical analysis is:

| | |
|---|---|
| **Sulfur** | **99.9%** |
| **Organic Impurities** | **0.02% Max.** |
| **Ash** | **0.01% Max.** |

## Economics

Figure I shows CLEANAIR investment requirements. Typical utilities and annual operating costs are set out in Tables II and III, respectively, for three tail gas clean-up cases.

| Case | Claus Unit Capacity, LT/D | Claus Recovery Efficiency, % |
|---|---|---|
| A | 50 | 95 |
| B | 150 | 95 |
| C | 500 | 95 |

In all cases the design basis is 250 ppmv equivalent $SO_2$ in the effluent before incineration and dilution. Further, the Claus unit is assumed to be existing and no provisions are included in the Claus unit to minimize tail gas clean-up requirements. The costs can vary with the hydrocarbon, carbon dioxide and hydrogen sulfide content of the acid gas feed to the Claus unit as well as the static pressure of the tail gas.

**INVESTMENT**

| Case A | Case B | Case C |
|---|---|---|
| $925,000 | $1,400,000 | $2,200,000 |

## SUMMARY

Disclosure of technical details of CLEANAIR requires execution of a secrecy agreement. A questionnaire is available from J. F. Pritchard & Company to delineate gas conditions and composition for individual plant applications. Order-of-magnitude investment costs and expected operating costs can be furnished on a non-confidential basis.

Pritchard and TGS maintain the pilot plant at the Okotoks, Alberta, Canada, plant for client demonstration. Arrangements can be made also for client visits to Stretford plants.

**TABLE II**
**UTILITIES SUMMARY**

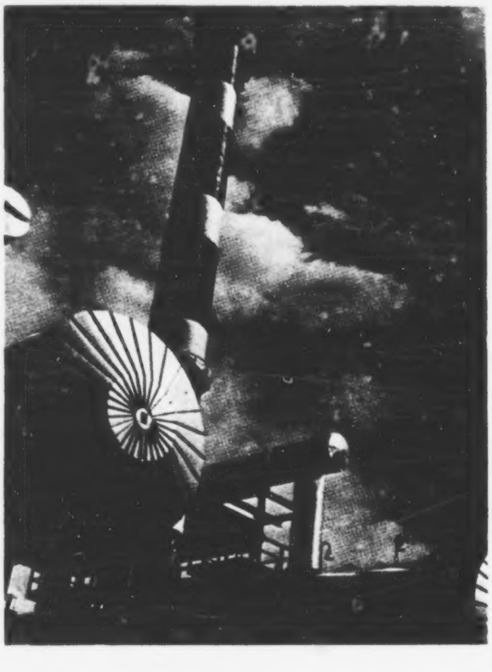
| Item | Conditions | Units | Usage<br>Case A | <br>Case B | <br>Case C |
|---|---|---|---|---|---|
| Steam | 50 psig, saturated | Lb/Hr. | 400 | 1200 | 4000 |
| Cooling Water | 90°F, 30 psig, 15°F rise | GPM | 475 | 1400 | 4550 |
| Electricity | 220/440/2160 volts, 3 phase, 60 hertz | KW | 200 | 580 | 1900 |
| Fuel Gas | 900 BTU/scf, 40 psig | SCFH | 500 | 1500 | 4500 |

**TABLE III**
**ANNUAL OPERATING COSTS (365 Days/Yr. BASIS)**

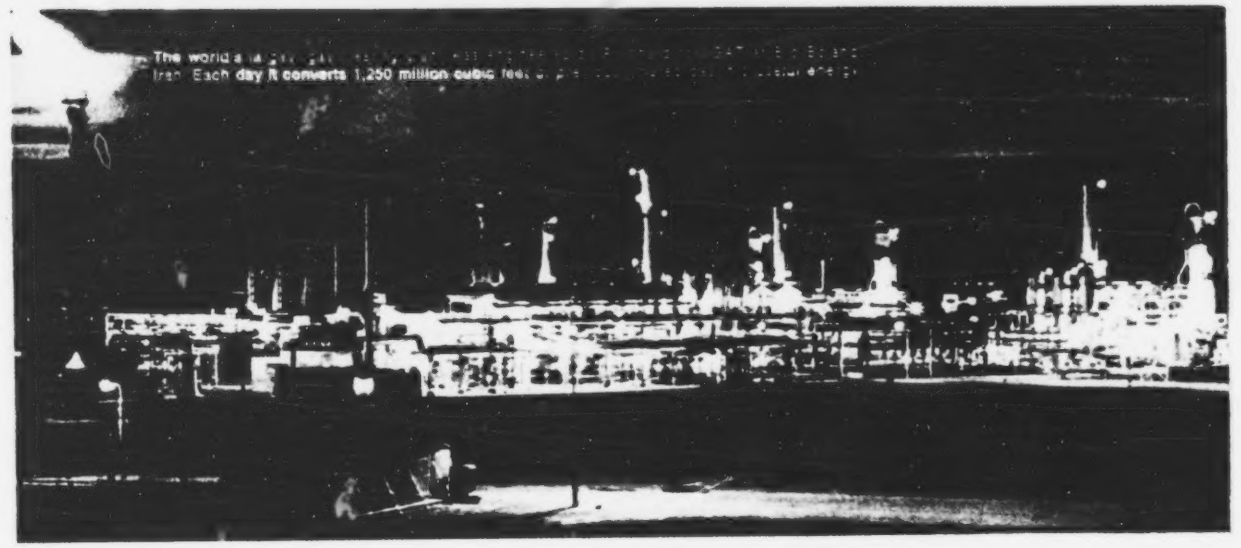
| Item | Unit | Annual Cost<br>Case A | <br>Case B | <br>Case C |
|---|---|---|---|---|
| Steam | $.40/1000 lb. | $ 1,400 | $ 4,200 | $14,000 |
| Cooling Water | $.02/1000 gal. | 5,000 | 14,700 | 48,000 |
| Electricity | $.007/KWH | 12,200 | 35,600 | 116,500 |
| Fuel Gas | $.45/1000 SCF | 1,600* | 5,900* | 17,700* |
| Chemicals | $1.75/LT of S in TG | 1,600 | 4,800 | 16,000 |
| Operating Labor | ¼ man/shift @ $7/MH | 15,300 | 15,300 | 15,300 |
| Depr. & Finan. | 15% of fixed capital inv. | 138,800 | 210,000 | 330,000 |
| Maintenance | 3% of F.C.I. | 27,800 | 42,000 | 66,000 |
|  | TOTAL | 203,700 | 332,500 | 624,500 |

*In most cases incineration will not be necessary. Costs shown are for actual process fuel requirements not including incineration.

A net credit for fuel gas can be taken resulting from savings in incineration when CLEANAIR is added to a Claus unit. Actual fuel requirements for incineration are reduced by 40%.



Sulfur converters and waste-gas chimney of a typical Claus- type recovery plant.


The world's [illegible]
Iran. Each day it converts 1,250 million cubic feet [illegible]

## Pritchard's growth embraces world-wide engineering, procurement and construction capabilities.

Pritchard has enjoyed rapid growth within the last decade. In keeping with our fiftieth annniversary in 1970, was the achievement of a greatly expanded sales and engineering staff and procurement and financing connections to keep pace with world-wide construction.

Shortly thereafter, a fifty million dollar project was acquired on a lump sum basis, involving a giant Liquefied Natural Gas facility at Skikda, Algeria.

The world's largest gas treating plant, a vital unit in the IGAT project, has gone on stream at Bid Boland, Iran. Many other projects, in gas treating, petrochemicals, sulfur removal and environmental processes to clean-up pulp and paper effluent were contracted for and constructed around the world.

Pritchard has also taken steps to bring this global capability **close to you.** Sales and/or engineering offices are located in Houston; New York; Los Angeles; Calgary; London; Köln; Paris; Sydney; Beirut and Tokyo. (See listing of affiliates and addresses, on this page.)

Top management control and turn-key performance are the ingredients of our success story. We welcome any inquiry, large or small, regarding our process technology and how it can contribute to your expansion programs.

THE **Pritchard** COMPANIES
4825 ROANOKE PARKWAY • KANSAS CITY, MO. 64112
HOUSTON • NEW YORK • LOS ANGELES • CALGARY
LONDON • KOLN • PARIS • SYDNEY • BEIRUT • TOKYO
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## Clean Up Gas Streams In **ONE EASY STEP**

H₂S Removal from Gas Streams

by the

process

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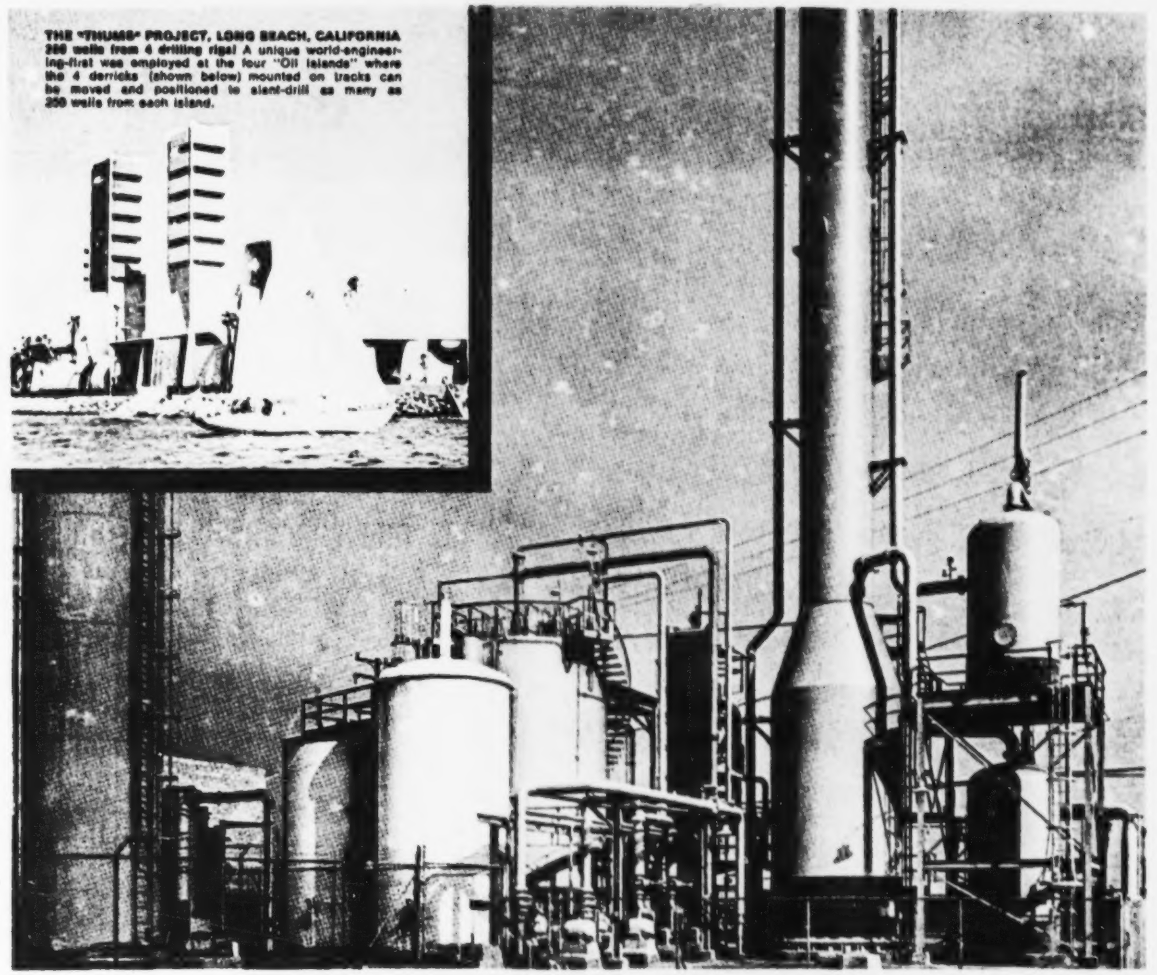

**THE "THUMS" PROJECT, LONG BEACH, CALIFORNIA**
**280 wells from 4 drilling rigs! A unique world-engineering-first was employed at the four "Oil Islands" where the 4 derricks (shown below) mounted on tracks can be moved and positioned to slant-drill as many as 200 wells from each island.**

## first in the U.S....

Latest addition to the famed Long Beach "THUMS" project is this Stretford facility, engineered and constructed by J. F. Pritchard and Company, for the operator, Lomita Gasoline Company at Long Beach, California.

It was the first plant built in the United States using the proven Stretford Process to clean up gas streams in addition to being the first facility anywhere in the world to apply this process to the purification of natural gas from oil wells. It incorporates exclusive new technology developed by Pritchard from extensive experience in engineering and constructing sulfur recovery plants.

The oil from the surrounding Wilmington Field supplies the feed gas. The name "THUMS" is an acronym for **T**exaco, **H**umble, **U**nion, **M**obil and **S**hell, the oil companies, who with Standard of California, Atlantic-Richfield and Signal Oil & Gas, jointly cooperated with the City of Long Beach and Lomita in underwriting the facility cost.

Pritchard has also developed process improvements to extend the process applicability to a wide range of gases which can be purified economically, thus improving the efficiency of future plants. Plants are normally designed to produce a treated gas containing not more than 4 parts per million by volume (ppmv) of $H_2S$. However, if required, as little as 0.2 ppmv can be achieved by the Stretfort Process.

# SULFUR RECOVERY

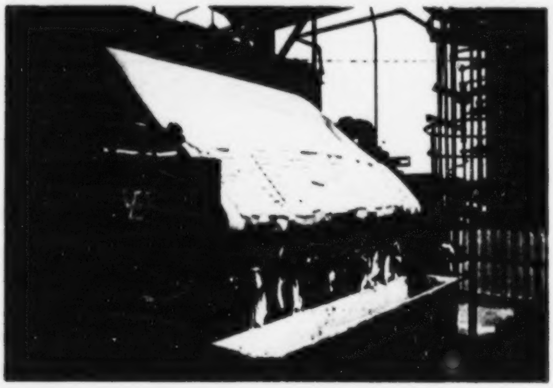
## by the "Stretford Process"... Licensed to Pritchard for world-wide application

**A significant contribution** to pollution abatement measures is the widely proven "Stretford Process" which removes hydrogen sulfide from sulfur-bearing gas streams including "sour" natural gas, refinery gas, industrial plant effluents and coke oven gas.

Originally developed by the North Western Gas Board of England, the process is licensed to Pritchard for world-wide application and ties in with technology developed by Pritchard in over 50 years of experience with gas processing, sulfur removal, petrochemical production and Claus plant tail gas clean up.

The Stretford Process has been commercially proven in more than 50 plants around the world (about half in the British Isles) over a period of many years.

Pritchard engineers are confident of performance, and studies or consultation services are offered for formal presentation to pollution control authorities even under strict code requirements. Elemental sulfur removed is normally 99.5% pure.



This photograph shows sulfur cake being discharged from the vacuum filter at the THUMS facility operated by Lomita Gasoline Company at Long Beach, California.

the Systems [illegible]
in the [illegible]

THE QUEEN'S AWARD TO INDUSTRY

1 9 6 8

## HISTORY

Generally recognized as a breakthrough, the Stretford Process of gas purification dates back to the early 1960's. In 1968 the Stretford Process received the Queen's Award to Industry for technical innovation.

Based on the use of an aqueous alkaline solution of salts of one or several anthraquinone disulphonic acids (ADA), it constitutes a continuous liquid process for the removal of hydrogen sulfide from gas streams.

The Stretford process was originally developed for the purification of coal gas, and proved so successful that it is being applied for the purification of gases as different as coke-oven gas, reformed petroleum products, natural gas and even the effluents from the manufacture of yarn, paper, foil and other industrial products.

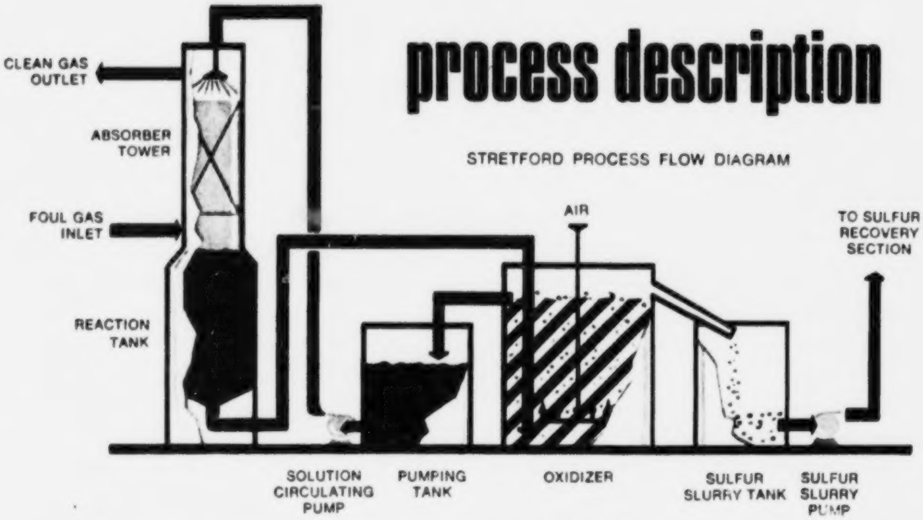
Continued research and experience have yielded many refinements and improvements, making the Stretford Process commercially and economically attractive, especially in our increasingly anti-pollution, ecology-conscious world.

The Stretford Process, originally developed to meet British Statutory restrictions limiting $H_2S$ in coal gas, down to 1.5 ppmv, has now been refined and improved in so many ways that it becomes the ultimate choice and the most economical overall, in both capital and operating costs.

Pritchard's Stretford plants recover sulfur having a purity of better than 99.5%, eliminating the effluent problem and yield a product in saleable form, in many cases amortizing part of the investment.

**SUMMING UP:** Pritchard's expertise in advanced Stretford application offers the most flexible and sophisticated method available for the effective, **complete, one-step** removal of $H_2S$. And secondly, it is the most economical in both capital and operating costs for most applications.

# process description


STRETFORD PROCESS FLOW DIAGRAM

A generalized process flow diagram of the Stretford plant is shown above. The gas stream enters an absorption column where the $H_2S$ is absorbed by gas contact countercurrently with the Stretford solution.

**Soda Ash**—When carbon dioxide is present in the gas stream, a mixture of sodium carbonate and sodium bicarbonate is formed giving a solution of stable pH normally in the range of 8.5 to 9.5. This provides the alkaline solution for initial $H_2S$ removal from the gas stream with the formation of hydrosulphide.

**Sodium Meta Vanadate**—When reacted with $HS^-$, vanadium reduces from 5 valent to 4 valent resulting in the precipitation of sulfur.

**Sodium Potassium** Tartrate (Rochelle Salt)—Prevents deposition of vanadium in over-loaded (upset) solutions.

**Anthraquinone Disulphonic Acid** (ADA)—the 2:7 isomer of ADA oxidizes 4 valent vanadium to 5 valent.

The $H_2S$ is absorbed and the clean gas stream is recovered for other use. Outlet $H_2S$ loading depends on design and can be guaranteed to be as low as 0.2 ppm in certain applications. It should be pointed out that more than 25 Stretford plants are operating in Great Britain and Northern Ireland, where the maximum level of $H_2S$ permitted is 1.5 ppm. Most of these plants have demonstrated on a continuous basis exit loadings of less than 1 ppm.

The Stretford solution, after recirculation through the $H_2S$ absorber, is retained for 10 minutes to allow for completion of the reaction between HS and vanadium. This hold up can be in the bottom of the absorber vessel or in a separate tank. From the hold tank, the solution passes to the oxidizer vessel where air is sparged upward through the solution.

## A SIMPLIFIED SUMMARY OF THE REACTIONS INVOLVED IN THE STRETFORD PLANT FOLLOWS:

1. **Soda Ash (Sodium Carbonate)—Provides the alkaline solution for initial absorption of $H_2S$ and formation of hydrosulphide ($HS^-$).**

   **$H_2S + Na_2CO_3 \longrightarrow NaHS + NaHCO_3$ (Absorber)**

2. **Sodium Meta Vanadate—Reacts with $HS^-$, is reduced from 5 valent to 4 valent and this precipitates sulfur from the hold tank.**

   **$HS^- + V^{(5+)} \longrightarrow S + V^{(4+)}$ (Hold tank)**

3. **Anthraquinone Disulphonic Acid (ADA)—Reacts with the 4 valent vanadium, converts it back to 5 valent and is itself reduced.**

   **$V^{(4+)} + ADA \longrightarrow V^{(5+)} +$ reduced ADA**

4. **Oxygen from air converts reduced ADA back to the oxidized state.**

   **Reduced ADA $+ O_2 \longrightarrow ADA + H_2O$ (Oxidizer)**

5. **Overall reaction is—**

   **$2H_2S + O_2 \longrightarrow 2H_2O + 2S$**

A small excess of vanadium ion is helpful in preventing solution overloading due to variations in gas flow and $H_2S$ content, but usually is uneconomic if upsets occur rarely. Conversely, too little vanadium allows formation of thiosulphate and concomitant solution loss through purging. Pritchard's knowledge of operating plants in the petro-chemical industry allows an optimum design on each individual plant. Pritchard is well qualified and happy to issue an economic analysis embracing capital and operating costs on an individual plant basis.

The sulfur formed in the Stretford process is finely divided and is floated to the top of the oxidizer by the air. The sulfur forms a froth containing 6 to 8% sulfur at the top of the oxidizer. This froth overflows to a settling tank where the sulfur slurry is accumulated for subsequent recovery. Underflow from the oxidizer is sent to the absorber pump tank for recirculation to the $H_2S$ absorber.

The sulfur is fed to an autoclave where heat is applied to melt the sulfur. The sulfur-water mixture is separated, and liquid sulfur of greater than 99.5% purity and commercially acceptable is obtained. Sulfur purity depends largely on the amount of impurities such as tars and light oils present in the original gas stream. When these are absent the sulfur purity can be as high as 99.9%.

None of the constituents used in the Stretford process has proved hazardous in years of operation. No special handling precautions are necessary.

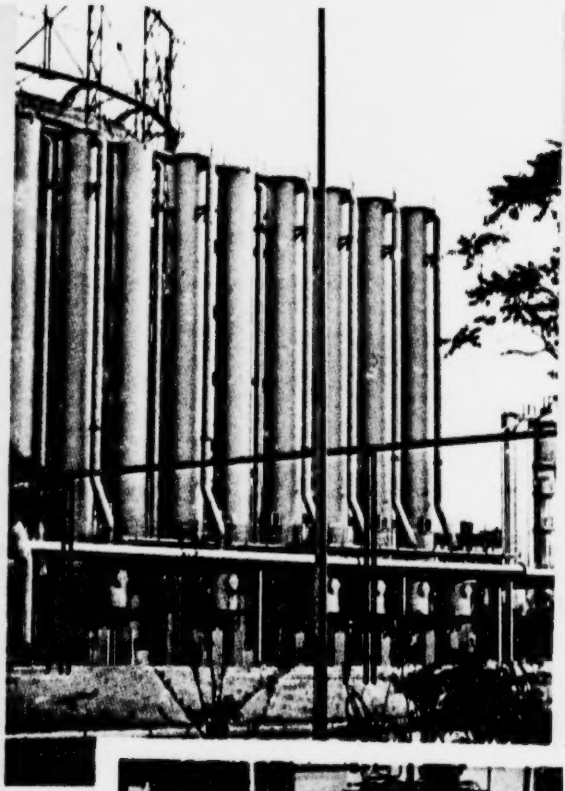
**A.** A unique feature of the Stretford plant at Zurich, Switzerland is the application of nine washing towers, accommodating three separate streams. Each stream has a capacity of 7 mm SCF/D. (photo courtesy N.W.G.B.)

**B.** Photo shows compressor and pump house with control panel. Stretford plant, Bristol, England.

**C.** **Stretford Plant,** Long Beach, California. A view of the plant taken during start-up. This plant purifies 55 mm SCF/D of oil field gas containing 0.15% $H_2S$.

**D.** **Stretford Plant,** Bristol, England. Two parallel streams, each 8 mm SCF/D coal gas. Exit gas purity less than 1ppm.

**E.** **Stretford Plant,** Belfast, Ireland. Dual absorption columns, oxidizers & solution inventory tanks.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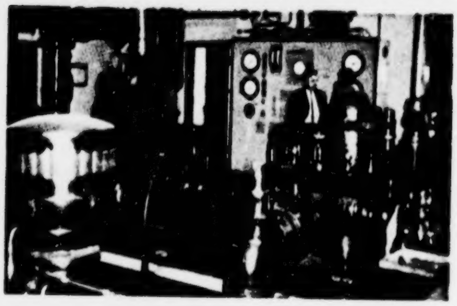
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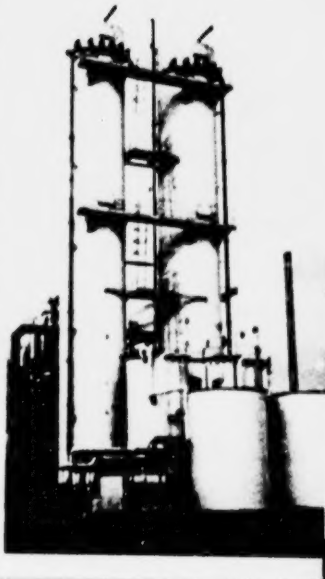
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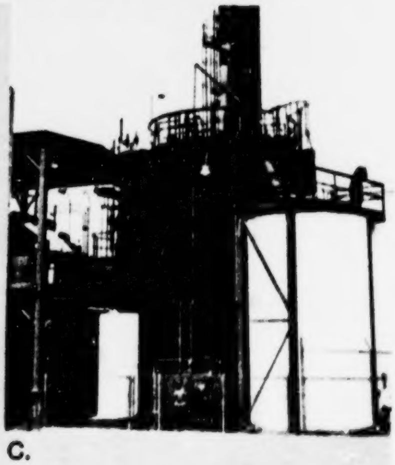
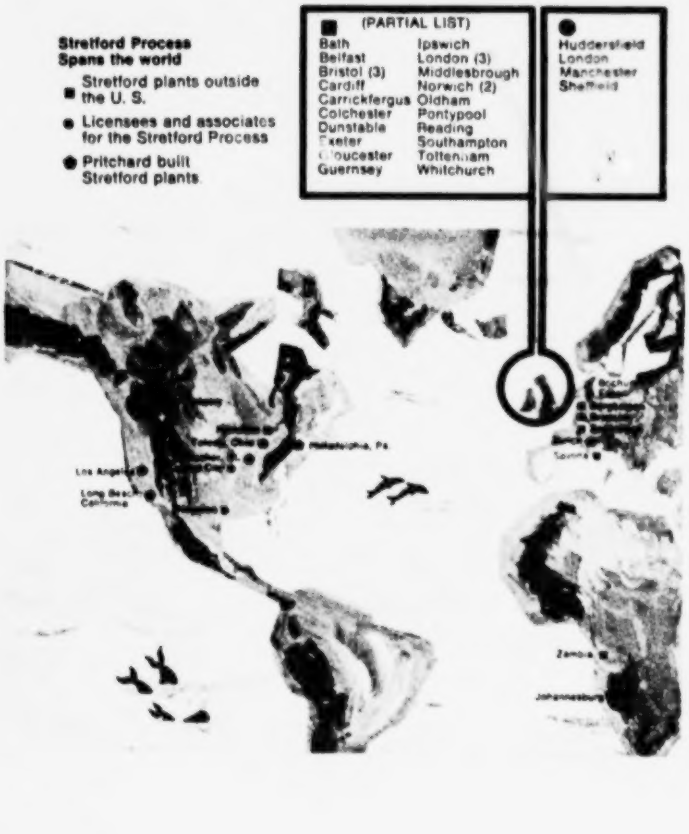

C.

# economics

| Feedstream | Plant A<br>Natural Gas at Wellhead | Plant B<br>Refinery Synthesis Gas |
|---|---|---|
| Flow rate—MMSCFD | 55 | 49 |
| Inlet sulfur loading-ppmv | 1490 | 14 000 |
| Outlet sulfur loading (guaranteed)-ppmv | 2.5 | 10 |
| **Capital Cost** | $800,000 | $1,100,000 |
| **Yearly Operating Cost** | | |
| Chemicals | $ 1,200 | $ 16,000 |
| Electricity | 10,000 | 40 500 |
| Steam | None | 500 |
| Operating Manpower | None | 19,000 |
| Maintenance (3% of FCI) | 24,000 | 33 000 |
| Depreciation (15% of FCI) | 120,000 | 165,000 |
| Total | $166,000 | $ 274 000 |
| Overall cost of operation in $/long ton sulfur | ** | $ 30 00 |

**Product quantity too low to warrant recovery for sale.



**Stretford Process Spans the world**

- ■ Stretford plants outside the U. S.
- ● Licensees and associates for the Stretford Process
- ⬢ Pritchard built Stretford plants

■ (PARTIAL LIST)

Bath
Belfast
Bristol (3)
Cardiff
Carrickfergus
Colchester
Dunstable
Exeter
Gloucester
Guernsey
Ipswich
London (3)
Middlesbrough
Norwich (2)
Oldham
Pontypool
Reading
Southampton
Tottenham
Whitchurch

●
Huddersfield
London
Manchester
Sheffield

## Economics

Economics of the Stretford process have been proven. Inlet gas composition, operating pressure and outlet gas purity required determine both capital and operating costs. Generalized economic analyses can be misleading. Pritchard is happy to provide cost estimates for your problem gas stream.

However, shown here are two actual cases studied with an economic analysis for each.

Plant A involves low $H_2S$ loading while Plant B has high $H_2S$ loading. Both plants were designed to operate between 90 and 135 psig pressure on the inlet gas stream. No credits are assumed even though incineration and discharge into a high temperature stack is unnecessary with the Stretford system. A high quality, saleable sulfur product is obtained. Sulfur prices are heavily dependent on freight and as a consequence, economics vary with plant location.

Stretford plants are purifying gas streams of all kinds, ranging from a few thousand to more than 50 million cubic feet per day . . . from coke ovens, ore smelting, chemical plants, petroleum refineries and natural gas sources. Purification can be carried out at pressures ranging from atmospheric to more than 1,000 psig. Thus, each application is designed to meet specific problems and local conditions.

### CONSTRUCTION MATERIALS

Usually with mild steel throughout, with inert linings such as cold-cure epoxy resins for oxidation vessels and slurry tanks to avoid internal corrosion from sulfur deposits.

Pipework is of conventional construction throughout. Pumps are of the centrifugal type for liquor circulation and of the screw type for slurry handling.

The vertical washing tower or column is the most used type of purifying vessel, with the Stretford solution entering at top and the gas to be purified at the bottom.

Blowers or compressors, where required, may be of any suitable type, providing they deliver air free from oil. No special technical restrictions on oxidizer design are required. Caution should be observed to prevent the accumulation of sulfur deposits on unprotected metal surfaces in vessels and pipelines.

## Why Stretford?

Advantages of the Stretford Process:

1. Well proven commercial operation over many years and a wide variety of gas streams.
2. Provides complete clean up of $H_2S$ to well below 1-ppmv if required.
3. Extremely flexible operation with high turndown ratio.
4. Requires little operator attention. All process streams are handled as liquids, making for inexpensive automation.
5. Good process control can be maintained by simple analytical testing with little technical supervision.
6. Short start-up and shutdown period.
7. Mild steel construction primarily.
8. No special handling required of the aqueous Stretford solution or stored makeup chemicals.
9. Low chemical consumption.
10. Low maintenance.
11. Recovers contaminants as a saleable, widely-used material.
12. Plants may be operated over a wide range of pressures.

## Why Pritchard?

In addition to the above listed advantages inherent in the Stretford Process, Pritchard offers the following exclusive improvements to the basic process:

1. Easy, trouble-free production of bright molten sulfur.
2. Increased efficiency of the oxidation step.
3. Optimization of the absorber tower design . . . all adding up to improved economics!

*Cable or Call Us, About Your Ecological Problems*

Our engineers love to talk technology.

**PHONE: (816) 531-9500**

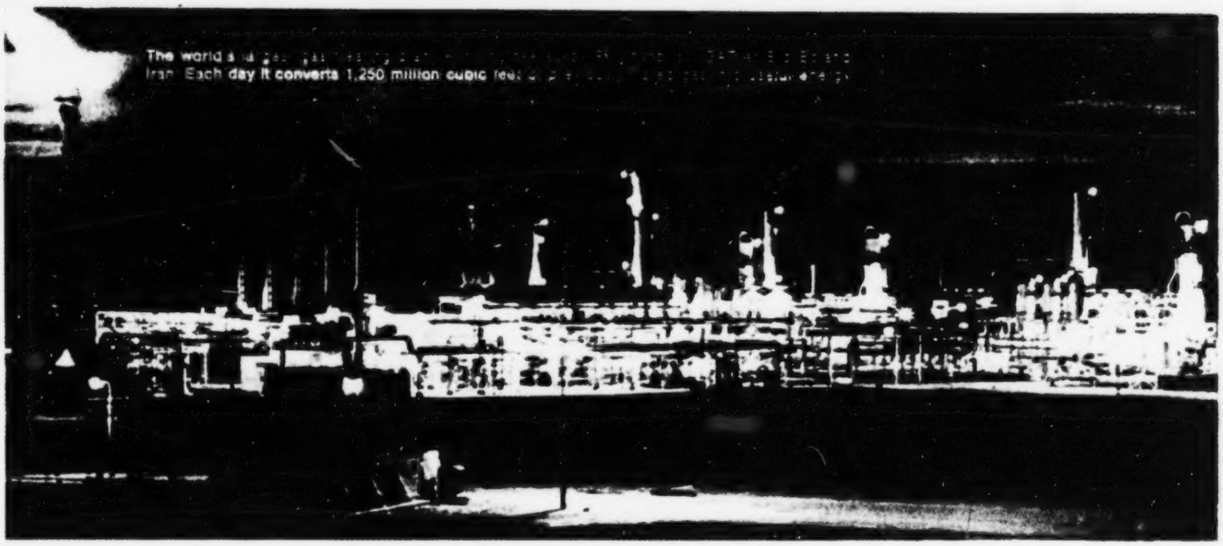
Or, if you are overseas, contact any of our offices near you, shown on back page of this folder. The meter won't be running!

FORM SP 5M 7112

## Some Typical Stretford Plants

| Plant Location | Type of Gas | Gas Feed MMSCFD | $H_2S$ Inlet Loading |
|---|---|---|---|
| Amagasaki, Japan | Coke Oven | 48 | 0.3% |
| Belfast, N. Ireland | Refinery/Reformed | 45 | 16-200 ppm |
| Bergkamen, W. Germany | Coke Oven | 38 | 0.6% |
| Carrickfergus, N. Ireland | CS2 Retort | 0.1 | 60% |
| Colchester, England | Otto Reformer | 6 | 30 ppm |
| Guernsey, Channel Islands | Reformed Petroleum | 3 | 30 ppm |
| Hamilton, Ontario | Coke Oven | 28 | 0.64% |
| Johannesburg, S. Africa | Producer | 8 | 0.15% |
| London, England | Water Shift | 65 | 200 ppm |
| New Delhi, India | Chemical Process | 0.1 | 100% |
| Taiwan | Coke Oven | 11.8 | 1.25% |
| Zambia | Ammonium Nitrate Plant | 10 | 1.5% |
| Zeebrugge, Belgium | Coke Oven | 14 | 0.5% |
| Zurich, Switzerland | Coke Oven | 21 | 0.5% |
| Long Beach, California | Natural (Oilfield) | 55 | 0.15% |
| Toledo, Ohio | Refinery | 49 | 1.9% |
| Herscher, Illinois | Natural | 45 | 0.06% |
| Philadelphia, Penna. | (Part of a CLEANAIR plant— 1 ton sulfur per day) | | |
| Los Angeles, California | (Part of a CLEANAIR plant— 40 tons sulfur per day) | | |

All U.S.A. plants to date are of Pritchard design and construction. The Long Beach plant went on stream May, 1971, followed by two plants in the Spring of 1972, and two more in early 1973.


The world's [illegible]
Iran. Each day it converts 1,250 million cubic feet [illegible]

**Pritchard's growth embraces world-wide engineering, procurement and construction capabilities.**

Pritchard has enjoyed rapid growth within the last decade. In keeping with our fiftieth annniversary in 1970, was the achievement of a greatly expanded sales and engineering staff and procurement and financing connections to keep pace with world-wide construction.

Shortly thereafter, a fifty million dollar project was acquired on a lump sum basis, involving a giant Liquefied Natural Gas facility at Skikda, Algeria.

The world's largest gas treating plant, a vital unit in the IGAT project, has gone on stream at Bid Boland, Iran. Many other projects, in gas treating, petrochemicals, sulfur removal and environmental processes to clean-up pulp and paper effluent were contracted for and constructed around the world.

Pritchard has also taken steps to bring this global capability **close to you.** Sales and/or engineering offices are located in Houston; New York; Los Angeles; Calgary; London; Köln; Paris; Sydney; Beirut and Tokyo. (See listing of affiliates and addresses, on this page.)

Top management control and turn-key performance are the ingredients of our success story. We welcome any inquiry, large or small, regarding our process technology and how it can contribute to your expansion programs.

**THE Pritchard COMPANIES**
**4625 ROANOKE PARKWAY • KANSAS CITY, MO. 64112**
HOUSTON • NEW YORK LOS ANGELES • CALGARY
LONDON • KOLN • PARIS SYDNEY • BEIRUT • TOKYO
Subsidiaries of International Systems & Controls Corporation

# APPENDIX L - CHIYODA CHEMICAL ENGINEERING & CONSTRUCTION CO., LTD. INFORMATION

**CHIYODA** CHEMICAL ENGINEERING
& CONSTRUCTION CO., LTD.

CABLE ADDRESS: CHIYOTAKA YOKOHAMA
TELEX : CHIYO J47726 (Overseas Line)
3822541 CHIYO J (Domestic Line)

P.O. BOX 10, TSURUMI, YOKOHAMA, JAPAN
TELEPHONE: YOKOHAMA (045) 521-1231

June 21, 1972

Mr. W.D. Beers
Project Manager
Processes Research Inc.
6881 Farmbrook Drive
Cincinnati Oh. 45230
U. S. A.

Re: "Chiyoda THOROUGHBRED 101" Flue Gas Desulfurization Process

Dear Mr. Beers:

We wish to thank you for your interest in our "Chiyoda THOROUGHBRED 101" Flue Gas Desulfurization Process which appeared in the "Hydrocarbon Processing".

We are pleased to send you as enclosed a copy of the brochure entitled "Chiyoda THOROUGHBRED 101" Flue Gas Desulfurization Process which we hope will serve your techno-economic evaluation purpose.

The main characteristic of our "Chiyoda THROUGHBRED 101" Flue Gas Desulfurization Process is to use dilute sulfuric acid to absorb $SO_2$ at a high efficiency desulfurization rate of approximately 97%, producing only gypsum as the end product.

As explained in the enclosed descriptive information, our Process promises a wide range of operation flexibility with simple process flow and low plant construction and operation cost, and ensures continuously stable operation compatible with a wide range of fluctuating loads of flue gases generated from industrial plants.

Chiyoda has proved high efficiency performance of "Chiyoda THOROUGHBRED 101" Process by continuous operation for a period of over ten (10) months using a 1,000 $Nm^3$/hr. (or 650 scf/min.) pilot plant.

Chiyoda has been awarded contracts for the design, engineering and construction of commercial "Chiyoda THOROUGHBRED 101" plants from the following four companies in Japan:

| Client | Capacity | | Gas to be Treated |
|---|---|---|---|
| Nippon Mining Co., Ltd. | 33,500 | $Nm^3/h$ | Claus Tail Gas |
| Fuji Kosan Co., Ltd. | 158,000 | " | Boiler Flue Gas |
| Tohoku Oil Co., Ltd. | 14,000 | " | Claus Tail Gas |
| Mitsubishi Rayon Co., Ltd. | 90,000 | " | Boiler Flue Gas |

We thank you again for your interest in our Process and shall be pleased to hear from you of a specific inquiry.

With best regards,

Very truly yours,

M. Sato

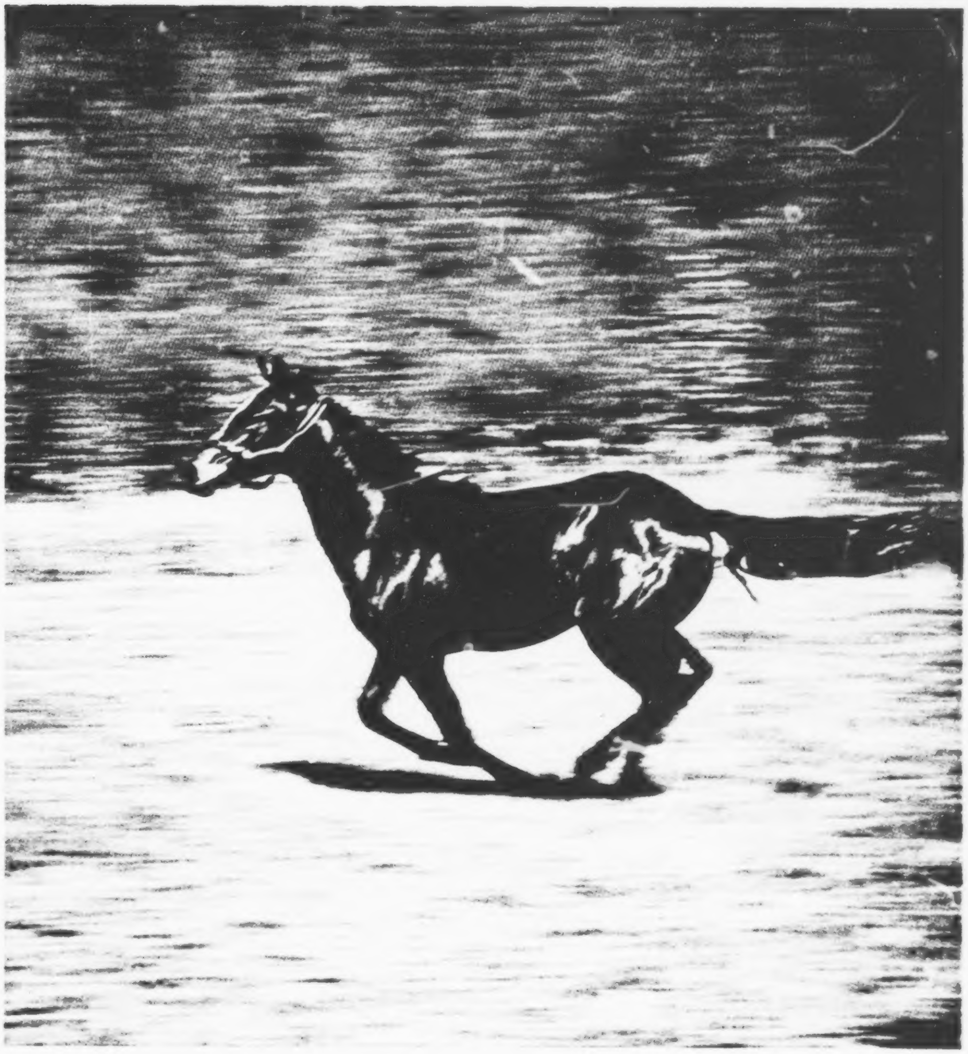
M. Sato
Executive Managing Director

KI/hy

Encl.

# The Chiyoda THOROUGHBRED 101

## Flue Gas Desulfurization Process



**CHIYODA** CHEMICAL ENGINEERING & CONSTRUCTION CO. LTD

# "Chiyoda THOROUGHBRED" Series of Environmental Control Technologies

With the remarkable industrial growth, great emphasis has been placed on the necessity of pollution control. We, at Chiyoda, fully recognizing the growing importance of providing preventive measures against environmental pollution, have been determined to challenge this difficult problem based on the total systems engineering approach. Since the types and conditions of pollutions are varying in nature, an overall systems approach is essential to find the best possible solution.

We are firmly determined to concentrate our technological efforts on the development of various technologies for environmental control to meet the need of the public and industry. It is for this reason that we have given a trade name "Chiyoda THOROUGHBRED" to the processes and equipment for environmental control with classification numbers coded to each category. "THOROUGHBRED" stands for the best race horse of a breed ever created through centuries of crossbreeding improvement. It is our sincere hope that the "Chiyoda THOROUGHBRED" series of environmental technologies will earn the same assessment and reputation.

Processes and equipment that must be developed should be such that they satisfy the universal need as viewed from long range demand forecasts and they should be developed to solve various problems relating to environmental preservation under a wide range of variable conditions.

With the energy innovation coming before us, it is imperative to place emphasis on the selection of systems that will provide logical solutions to the problems.

We solicit your continued kind patronage of our comprehensive services in the field of environmental control including plant safety control and earthquake damage prevention.

We avidly look forward to being of service to you.

A. Tamaki
President

# "Chiyoda THOROUGHBRED 101" Flue Gas Desulfurization Process

## 1. Flexible to Meet Various Conditions

Various processes of removing sulfur oxides from flue gases have been developed or are under development in the world. However, as each process has disadvantages and limitations with requirements for further improvement, it is of utmost importance to evaluate and select a process most suitable and flexible to meet each specific requirement.

"Chiyoda THOROUGHBRED 101" not only demonstrates high efficiency performance, but also displays other advantageous features. It only produces gypsum as a by-product which is completely harmless and nontoxic, and does not discharge any stream that will cause secondary pollution.

"Chiyoda THOROUGHBRED 101" is easy to operate, and has a highly reliable performance. In addition, capital, operating and maintenance costs are low. Processing cost of the by-product gypsum is only small. The solution in the absorption-oxidation section is not slurry, and thus ensures stable operation and is not detrimental to the operation of the boiler and other related equipment.

As "Chiyoda THOROUGHBRED 101" can separate the crystallization section from the absorption-oxidation section for installation at most any place desired, for instance, within the premises adjacent to a large thermal power plant or a large boiler, there poses no special problem in site selection. The process is a wet desulfurization method with a high sulfur removal rate, which eliminates the installation of a tall chimney.

## 2. Contributions to the Petroleum Industry

"Chiyoda THOROUGHBRED 101" ensures petroleum refineries an effective use of low-grade fuels such as asphalt for power generation and also pipestills.

Since "Chiyoda THOROUGHBRED 101" is of simple construction and has highly reliable operation, it is suitable for $SO_2$ removal from the tail gas of a sulfur plant.

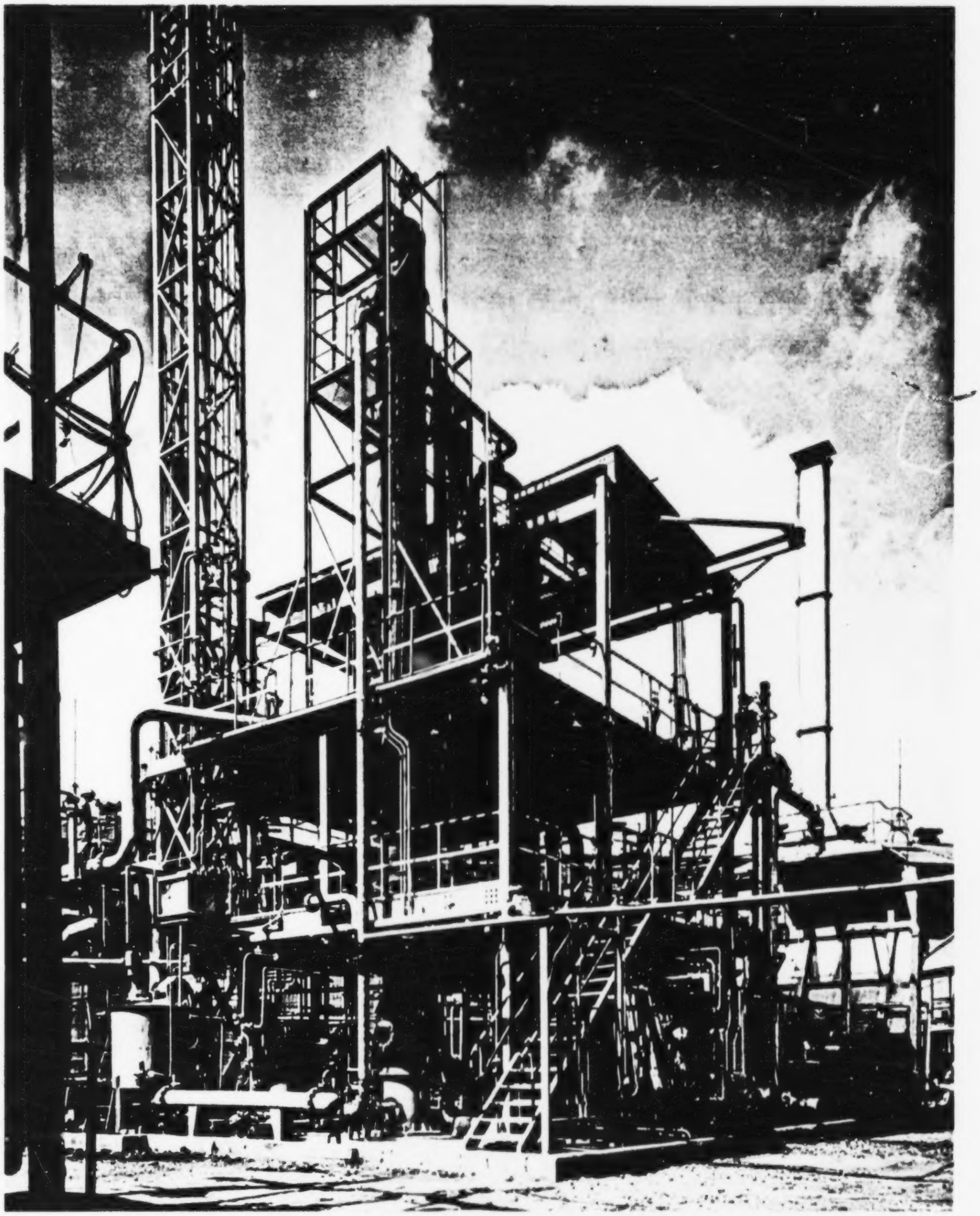
There are many cases where boilers and pipestills are located apart in the premises of petroleum refineries and petrochemical complexes, and large diameter ducts are laid to collect flue gases to centralized stacks. In these cases, "Chiyoda THOROUGHBRED 101" has an added advantage since the absorption-oxidation section can be installed separately in one or more places to pump sulfuric acid to a distant place where it is convenient to install a crystallizer to process the by-product gypsum.

## 3. Application to the Energy Industry

Currently, it is a common practice in Japan that a thermal power station is jointly built adjacent to a large petroleum refinery. For example, in the Mizushima and Sendai petrochemical complexes, thermal power stations were jointly constructed to rationalize utilization of energy.
Since a large amount of fuels is consumed by these power stations, tremendous savings are ensured, if low grade fuels such as asphalt can be used.

"Chiyoda THOROUGHBRED 101" ensures thermal power stations the use of low grade high sulfur fuels to convert them into electric power without air pollution problem, resulting in improved national environment . . . national interests.

A large quantity of the by-product gypsum can be utilized for housing construction materials and many other purposes as it is harmless to man and his surroundings. Furthermore, as this is a wet type flue gas desulfurization process, no particulate from stack is emitted even where coal is used with heavy fuel oils, and thus, no duct collector is required.



This 1000 Nm$^3$/h (650 scf/min) pilot plant operated continuously for over 300 days desulfurizing flue gas

# Process Description

As shown in the process flow scheme, "Chiyoda THOROUGHBRED 101" is comprised of three process steps.

Reactions take place in each step of the process sequence as follows:

Absorption......... $SO_2 + H_2O \longrightarrow H_2SO_3$
Oxidation ......... $H_2SO_3 + \frac{1}{2}O_2 \longrightarrow H_2SO_4$
Crystallization ... $H_2SO_4 + CaCO_3 + H_2O \longrightarrow$
$CaSO_4 \cdot 2H_2O$ (Solid) $+ CO_2$ (Gas)

## 1. Absorption

After being removed of dust and pre-cooled in the prescrubber, flue gas is led into absorber where $SO_2$ and $SO_3$ contained in the flue gas are absorbed and removed by dilute sulfuric acid at 50~70°C (120~160°F).

Absorption can be carried out in a column. The absorber can be of any type with simple construction to meet the purpose.

In $H_2SO_4$ of 2—10 wt % concentration, $SO_2$ can only be soluble to a range of one-third of the solubility to water, but the dilute sulfuric acid recycled from the succeeding oxidation section dissolves oxidation catalyst and $O_2$ nearly to the saturation point. Thus, as oxidation reaction can take place in the absorption section also, recycle rate of three times the water is not required. In the absorption section, $SO_2$ content in the exhaust gas can be held to below 100 ppm, depending upon the size of the absorber, or flow rate and concentration of dilute sulfuric acid.

In the pilot plant test with a six meter (eighteen foot) high packed column, combustion gas of vacuum residue containing $SO_2$ of 3,000 ppm was absorbed by 3 wt % sulfuric acid, and it was successful in holding the $SO_2$ content in the exhaust gas to below 50 ppm.

The treated gas passes to the atmosphere at about the same temperature with dilute sulfuric acid.

The dust collected in the prescrubber can be removed from the process, if it affects the gypsum quality.

## 2. Oxidation

Sulfurous acid in the dilute sulfuric acid is completely oxidized into sulfuric acid. And a part of sulfuric acid ($H_2SO_4$ corresponding to $SO_2$ and $SO_3$ removed from the flue gas) is passed into the crystallizer to process gypsum and the remainder is circulated into the absorber.

In this section is used a special catalyst to accelerate oxidation. The special catalyst used has been specifically developed by Chiyoda after continuing research and development efforts, and has been evaluated most suitable for the purpose from the standpoint of catalyst activity, poison resistibility and cost.

Type and size of the oxidizer vary with the oxidation agent, absorption velocity, reaction velocity, etc. It is recommended to use a bubbling column of simple design which can utilize air as oxidation agent.

Air consumption is about five times the theoretical requirement.

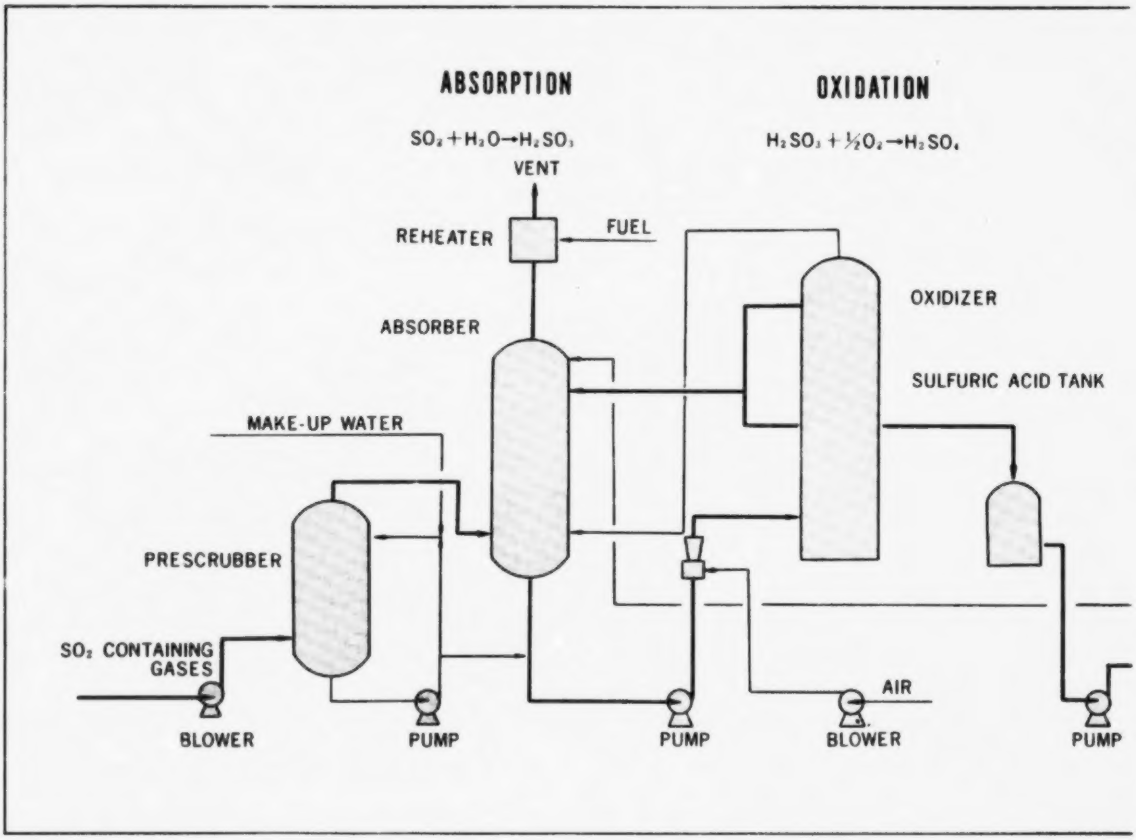
## 3. Crystallization

Sulfuric acid sent from the oxidizer is neutralized with calcium compounds to continuously crystallize and separate gypsum.

This process allows choice of any of a variety of calcium compounds, such as natural limestone, quick lime or calcium oxide, slaked lime, calcium hydroxide and carbide residue.

Gypsum can be crystallized in varying sizes in the crystallizer of special design. Crystals thus formed are continuously separated by centrifuge and water washed to produce the product gypsum.

The mother liquor and wash water is recycled to the absorber, thus, there is no effluent water drained out the whole system.


ABSORPTION
$SO_2 + H_2O \rightarrow H_2SO_3$
OXIDATION
$H_2SO_3 + \frac{1}{2}O_2 \rightarrow H_2SO_4$
VENT
REHEATER
FUEL
OXIDIZER
ABSORBER
SULFURIC ACID TANK
MAKE-UP WATER
PRESCRUBBER
$SO_2$ CONTAINING GASES
AIR
BLOWER
PUMP
PUMP
BLOWER
PUMP

# Features of "Chiyoda THOROUGHBRED 101"

### Simple Process Flow and Ease of Operation

With simple process flow and plant structure, the process promises a wide range of operation flexibility.

### Continuously Stable Operation

Unlike conventional wet type flue gas desulfurization systems, as no slurry is used in the absorption-oxidation section, there presents no problem of clogging. In addition, by virtue of its process flexibility, it ensures reliable continuous operation under a wide range of fluctuations in load.

### High-efficiency Desulfurization

Approximately 97% of desulfurization can be attained. In other words, $SO_x$ in the stack gas to be emitted can be held to 100 ppm or lower.

### Lower Construction, Operation and Desulfurization Costs

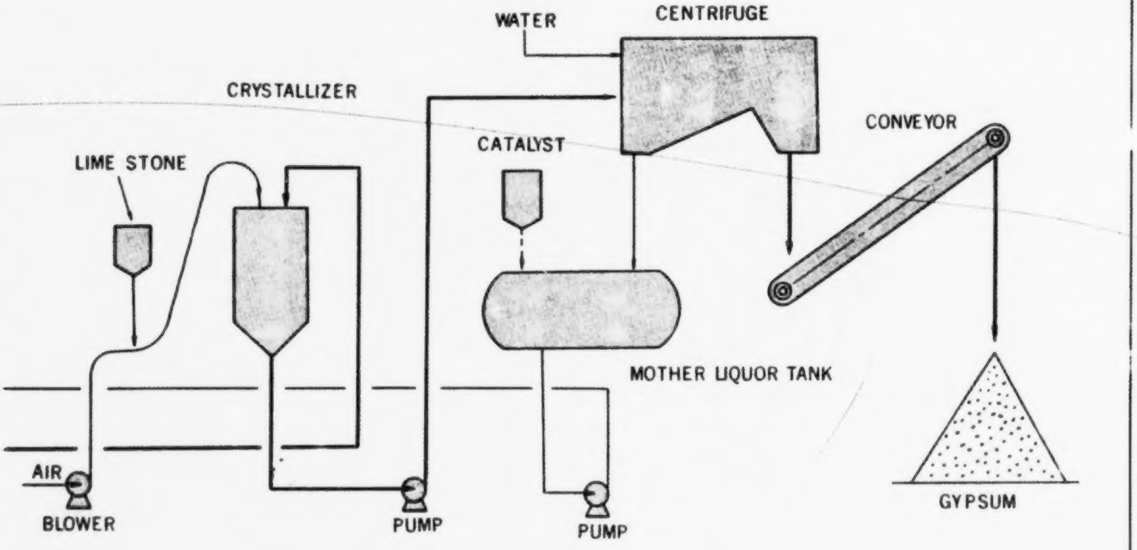
Because of its simple process, it minimizes the number of unit operations. Since there is no requirement for special chemicals and utilities, low running cost is assured, resulting in lower desulfurization costs.

### $SO_2$ Removal for Dirty Flue Gases

$SO_2$ can be removed economically even from low grade fuels such as combustion gases from vacuum residue, because of stable catalyst performance.

## CRYSTALLIZATION

$H_2SO_4 + CaCO_3 + H_2O \rightarrow CaSO_4 \cdot 2H_2O + CO_2$



### ● Dust Removal

No electrostatic precipitator is required since the soot and other particulates in the flue gas are removed in the prescrubber and absorption steps.

### ● No Waste Stream

Since there is no bleed of the solution, there is no concern of secondary pollution problem.

### ● By-Product Gypsum

Gypsum is a highly stable chemical compound of sulfur, and is harmless when stocked. There can be found versatile applications in place of natural gypsum. In Japan, since there is a lack of natural resource of gypsum, the by-product can be used as Portland cement retarder, gypsum boards and so on.

In addition, dilute sulfuric acid can be used as a pickling solution in steel mills, and can be sent to waste water treatment facilities to neutralize alkaline substances in chemical and petroleum industries.

### ● Flexible Combination of Process Steps

Since the absorption-oxidation section can be separately installed from the crystallization section, dilute sulfuric acid processed can be pumped through pipeline to a centralized crystallization section located in an adjacent gypsum board plant or cement plant.

# Investment and Utility Summary (Boiler Flue Gas Cases)
# "Chiyoda THOROUGHBRED 101"
# Flue Gas Desulfurization Process

| ITEM | DESCRIPTION | UNIT | QUANTITY | | | |
|---|---|---|---|---|---|---|
| Design Conditions | Flue Gas | $\mathrm{Nm^3/hr}$ (scf/min.) | 750,000 | (441,400) | 2,400,000 | (1,413,000) |
| | Power Generating Capacity | MW | 250 | | 800 | |
| | $SO_2$ Content in Flue Gas | p.p.m | 1,500 | | 1,500 | |
| | Flue Gas Temperature | ℃ (°F) | 140 | (284) | 140 | (284) |
| | Desulfurization Rate | % | More than 90 | | More than 90 | |
| | Service Factor of Boiler | % | 90 | | 90 | |
| | Fuel Oil Consumption in Boiler | Kl/year (barrel/year) | 482,000 | (3,032,000) | 1,540,000 | (9,687,000) |
| | Sulfur Content in Fuel Oil | % | 2.7 | | 2.7 | |
| By-product | Gypsum ($CaSO_4 \cdot 2H_2O$) | ton/hr (lb/hr) | 7.8 | (17,200) | 25.1 | (55,350) |
| Plant Cost (A) | | $ | 4,970,000 | | 11,850,000 | |
| Fixed Cost (B) | 18% of (A) | $/year | 894,600 | | 2,133,000 | |
| Direct Cost (C) | Limestone Powder $5.50/T (0.25¢/lb) | $/year | 202,400 | | 642,400 | |
| | Electricity 0.7¢/KWH | 〃 | 263,200 | | 812,000 | |
| | Industrial Water 2¢/T (8¢/1000gal) | 〃 | 8,000 | | 22,400 | |
| | Re-heat Fuel Oil $20/Kl (3.18$/barrel) | 〃 | 241,000 | | 770,000 | |
| | Catalyst | 〃 | 6,000 | | 19,000 | |
| | Labor $12,000/Year/capita | 〃 | 96,000 | | 144,000 | |
| | Maintenance 2% of (A) | 〃 | 99,400 | | 237,000 | |
| | Sub-Total | 〃 | 916,000 | | 2,646,800 | |
| Net Operating Cost (D) | (B) + (C) | $/year | 1,810,600 | | 4,779,800 | |
| Overhead (E) | 12% of (C) | 〃 | 109,900 | | 317,600 | |
| Operation Cost (F) | (D) + (E) | 〃 | 1,920,500 | | 5,097,400 | |
| By-product Credit | $5.50 /T (0.25¢/lb) | | 343,200 | | 1,104,400 | |
| Cost of Desulfurization | Without By-product Credit | $/Kl ($/bbl) | 3.98 | (0.63) | 3.31 | (0.53) |
| | | $/MWH | 0.96 | | 0.80 | |
| | | $/Kl ($/bbl) | 3.27 | (0.52) | 2.59 | (0.41) |
| | With By-product Credit | $/MWH | 0.79 | | 0.62 | |
| Required Area | Include 7 days Storage Area | $m^2$ ($1000ft^2$) | 3,600 | (38.7) | 11,500 | (123.7) |

Notes : The plant cost (A) is based on the Japanese cost.
Unit cost in U.S.A. is used in column (C).
(US $ 1.00=¥308)

# APPENDIX M - INSTITUT FRANCAIS DU PETROLE INFORMATION

February 24, 1972

Mr. Robert Dutriau
Institut Francais du Petrole
90 Park Avenue
New York, New York 10016

Subject: Claus Tail Gas Treatment

Dear Mr. Dutriau:

Several of the methods being considered for abatement of sulfur emission to the atmosphere include Claus sulfur units. The Environmental Protection Agency Office of Air Programs has engaged Processes Research, Inc., to gather information regarding the efficacy of Claus sulfur plants in pollution abatement (Contract No. 68-02-0242).

From the May 1971 issue of Hydrocarbon Processing, we understand that your company has developed a process for removing sulfur from Claus tail gases. Please let us have additional information available regarding the Institut Francais du Petrole Tail Gas Sulfur Recovery Process, as follows (tail gas treatment units having daily sulfur capacities of 1 ton, 10 tons and 100 tons, for Claus tail gas feed concentrations of 0.3 mole percent, 1.0 mole percent, and 4.0 mole percent of $H_2S + SO_2$ are of particular interest):

1. Confirm approximate investment, royalty, catalyst costs, solvent costs, and consumption of water, power and steam for IFP units having various daily sulfur capacities and various Claus tail gas feed concentrations of $H_2S + SO_2$.

2. Operator attendance and maintenance requirements.

3. Confirm percentage sulfur recoveries for various Claus tail gas concentrations of $H_2S + SO_2$.

4. What is the pressure drop of the gas through the IFP unit?

5. Is the quality of the sulfur recovered by the IFP process equal to that of Claus sulfur?

6. What, if any, air pollution is presented by entrainment of catalyst and solvent overhead from the packed tower? Is incineration advisable?

7. A principal cause of poor sulfur recovery in Claus plants is deviation from the optimum feed ratio of air to $H_2S$, resulting from inadequate

instrumentation or careless operation. This also results in deviations from the stoichiometric balance of $H_2S$ and $SO_2$ in the tail gas. Therefore the tail gases from Claus units having the greatest need for pollution abatement are likely to contain unbalanced and erratic quantities of $H_2S$ and $SO_2$. Is it feasible to use some of the acid gas from upstream of the Claus unit to maintain the ratio of $H_2S$ to $SO_2$ required by the IFP process?

8. The COS and $CS_2$ typical of Claus tail gas is understood not removed by the IFP process. Do you have other means of removing these?

9. The IFP process is understood to be effective in place of the second and third Claus stages. Is there basis for the IFP process replacing the Claus unit altogether?

We will appreciate receiving all the above information which you can make available to us. Please let us know when we may expect to receive it.

We thank you for your cooperation.

Very truly yours,

PROCESSES RESEARCH, INC.

W. D. Beers
Project Manager

WDB.fj

cc: G. S. Haselberger
M. R. Jaster
P. W. Spaite

**Institut Français du Pétrole**
North
American
Office

Mr. W. D. Beers
Project Manager
Processes Research, Inc.
2912 Vernon Place
Cincinnati, Ohio 45219

March 17, 1972

CR 1 P08 00

Dear Mr. Beers:

In reply to your letter dated February 24th 1972, I.F.P. is pleased to provide you with non confidential information on the I.F.P. Claus tail gas clean up process. We understand that this information will be used for your study on pollution abatement from Claus plants for E. P. A. office of Air Programs.

I am sending you attached a document on our process which contains:

- a process description and flow diagram
- reaction mechanism
- operating parameters
- typical economics for a plant tied with 30 and 140 T/D Claus plants.
- list of industrial references

Besides our demonstration operation with Delta Engineering in Canada during the summer of 1971, I.F.P. now has 6 months of successful operating experience in the first Japanese unit. 3 more units will start in Japan in April 1972 and one in Canada in July 1972.

In addition I have attached typical economics for our I.F.P. plants tied with a 100, 300 and 1500 T/D Claus plant, at different levels of $H_2S + SO_2$ contens in the tail gas.

I will answer the questions as they are listed in your letter:

Q 1 - See attached document. Paid up royalty figures are of the order of 10-20% of erected cost.

Q-2 - The process is very simple to operate and does not require any additional labor, above operators,attending the Claus plant. Maintenance can be estimated at 2% of erected cost per year.

./.

90 Park Avenue
New York, N.Y. 10016

Telephone (212) 986.3391
Telex IFPNY / 620 060

Q 3 - See attached document

Q 4 - Pressure drop is low and tail gas pressure is generally well above I.F.P. requirements.

Q 5 - Sulfur produced by I.F.P. process is pure and can be blended with sulfur produced by Claus plant. A typical analysis of I.F.P. sulfur is:

| | |
|---|---|
| ashes | 100 ppm |
| carbon | 100 ppm |
| S | 99.5 minimum (wt%) |

Q 6 - The treated gas from I.F.P. plant is meant to be incinerated before sending it to the stack. The purpose of this incineration is to burn the remaining sulfur compounds ($H_2S$, COS, $CS_2$) into $SO_2$. Solvent and catalyst show a very low volatilaty at operating temperature. Nevertheless small quantities are carried over with the treated gas and completely burn in the incinerator without creating any pollution problem.

Q 7 - The question of $H_2S/SO_2$ control is covered in the attached document. The basic I.F.P. design includes a bypass of small amount of acid gas in order to control to some extent the ratio. This is considered as a safety device in case of the close loop control on the Claus plant is out of service.

Q 8 - COS and $CS_2$ are inert in our process as stated in the attached document. Nevertheless means exist to get rid of most of COS and $CS_2$ in the Claus plant. This is achieved by the use of specific catalyst at higher temperature in the 1st stage which destroy COS and $CS_2$ by hydrolysis.

Q 9 - The I.F.P. process can replace the second and/or third catalytic stage. It does not replace the first stage, for the reason shown above (COS & $CS_2$).

I hope this information will be useful for your preliminary evaluation of I.F.P. process.

Do not hesitate if you have any question to contact me in New York. I.F.P. is interested to get a copy of your final study. Kindly let me know whether this is possible.

Looking forward to hearing from you, I remain,

Yours very truly,

R. Dutriau
Sales Engineer
North American Office

RD:cs
encls.

# THE IFP PROCESS FOR CLEANING UP CLAUS TAIL GAS

**The IFP process for cleaning up Claus plant tail gas offers natural gas processors the chance to boost overall sulfur recoveries to 99% levels. The IFP process is already being used in one Canadian and one Japanese plant. Actual performance meets design criteria. Four other plants utilizing the process are under construction.**

## Process description and reaction mechanism

The basic reaction of the IFP process is the same as that in the Claus unit itself:

$$2H_2S + SO_2 \rightleftharpoons 3S + 2H_20$$

The reaction is carried out in a catalyst-containing solvent. The first step of the reaction mechanism is that the $H_2S$ and $SO_2$ dissolve in the solvent, the extent to which the gases dissolve naturally being a function of their particular pressures. Then the catalyst combines chemically with the $SO_2$, $H_2S$ and sulfur to yield an active complex. This complex in turn reacts with additional feed $H_2S$ and $SO_2$ to produce elemental sulfur according to the reaction noted, constantly regenerating the active complex itself.

During the initial phase of the reaction, product sulfur dissolves in the solvent until the saturation point for the given temperature is reached. Thereafter sulfur is continuously separated from the reaction mixture, and the reaction is pushed to the right. Lower temperatures also favor sulfur production, but they must not be low enough to permit condensation of water, or solidification of the sulfur which would cause plugging. Optimum temperature range is 230-320°F.

## Advantages of the IFP solvent/catalyst system

a) high catalyst activity

b) good chemical and thermal stability of both solvent and catalyst

c) minimum volatilization losses of solvent due to low vapor pressure

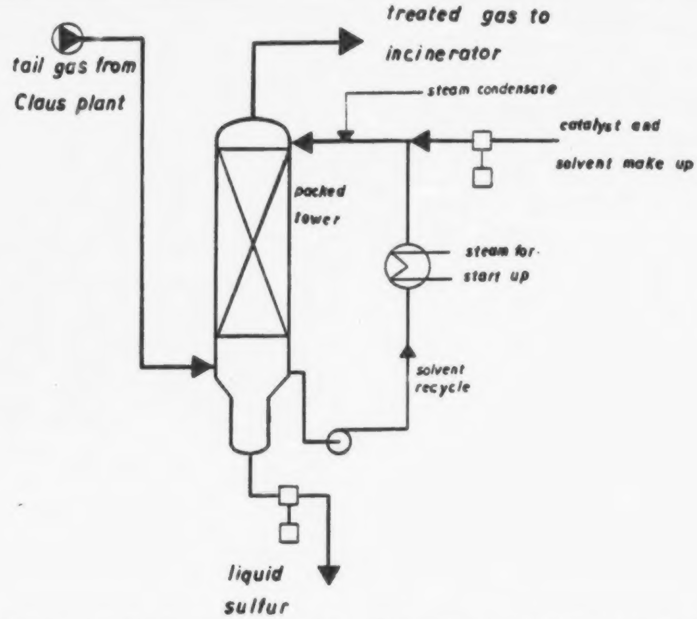
d) maximum gas/liquid contact, with no foam formation, because of good physical properties of solvent

e) ease of product separation due to low solubility of sulfur in solvent, and large difference in density

f) maximum product purity due to low solubility of solvent in sulfur

g) ready commercial availability and low cost of both solvent and catalyst

# FLOW SCHEME OF IFP PROCESS


treated gas to incinerator
tail gas from Claus plant
steam condensate
catalyst and solvent make up
packed tower
steam for start up
solvent recycle
liquid sulfur

The IFP process is exceptionally simple and requires only a few pieces of equipment. Claus tail gas at about 260°F is injected into the lower part of a packed column. The tower is designed for low pressure drop. One or more packed beds with redistribution are employed, depending on capacity. Product sulfur accumulates in a boot at the bottom of the tower and is continuously decanted under interface control.

The catalyst-containing solvent is circulated continuously from bottom to top of the tower to maximize liquid/gas contact by counter-current flow. Liquid temperature is maintained at 260-280°F, the heat of reaction being removed by vaporization of condensate injected into the solvent pump-around loop just prior to entering the top of the tower. Circulation is regulated to give optimum wetted packing surface in the tower.

Solvent degradation has not been found to occur, but some is lost in the overhead by evaporation even though vapor pressure is low at reactor temperatures. (These minute quantities of solvent are completely burned in the incinerator and cause no pollution problems.) No solvent is lost through entrainment. Losses are made up by replacement from a storage tank heated by a steam coil. The capacity of the storage tank may be as large as the total column and pump-around loop capacity.

Catalyst is also made up from a storage tank equipped with a mixer which holds a day's charge. Metering pumps are used to hold catalyst concentration constant and to compensate for losses in solvent. The heat exchanger shown in the circulation loop is used for start-up to raise the solvent to reaction temperature.

It is noteworthy that no buildup of water occurs. Since the solvent itself is not corrosive, construction is thus entirely of carbon steel, and plant investment is low.

### Total sulfur concentration in Claus gas

Conversions ($SO_2 + H_2S \longrightarrow S$) to be expected in the IFP process will depend on the total $H_2S + SO_2$ concentration in the Claus tail gas:

| $H_2S + SO_2$, Vol % | Typical conversion, %* |
|---|---|
| 0.4 – 0.8 | 80 |
| > 0.8 | 90 |

*In addition, the IFP process recovers 100% of free sulfur – both vapor and entrained droplets.

### $H_2S/SO_2$ ratio

From an operating viewpoint, only the ratio of $H_2S$ to $SO_2$ affects conversion rates. The ratio should be held between 2.0 and 2.4 if conversion is to be maximum. This should present no difficulty in modern gas processing practice: even though feeds to the Claus unit may fluctuate widely in both flow rate and composition, in-line gas chromatographic or UV spectrophotometric monitors can be used to regulate the $H_2S/SO_2$ ratio in the Claus tail gas ± 5%. Controlling the ratio not only maximizes sulfur recovery in the IFP unit, but it also keeps sulfur recovery at the highest level in the Claus plant itself.

### COS and $CS_2$ content

The only other process variable that can affect sulfur recovery adversely is the concentration of COS and $CS_2$ in the feed to the IFP unit. Even though significant amounts of these compounds are formed in the Claus burner, the first Claus catalytic reactor can bring levels of COS and $CS_2$ well under 1000-1500 ppm. The level remains essentially unchanged in the second and third stages, and is unchanged in the IFP unit, as the IFP process does not touch COS and $CS_2$.

The first Claus reactor should be run hotter than usual to keep COS and $CS_2$ at a minimum. Bauxite can also be replaced with a more sophisticated catalyst. The slightly lower conversion encountered when running the first reactor hotter will be more than offset by the higher sulfur recovery in the IFP unit.

### Summary

Holding the $H_2S/SO_2$ ratio in the range 2.0-2.4, and running the Claus plant to keep COS and $CS_2$ down, can provide overall sulfur conversions of more than 99.0% for the combined Claus-IFP system. This is equivalent to stack $SO_2$ emissions of about 1500 ppm after incineration.

## TYPICAL ECONOMICS OF IFP PROCESS

| | | |
|---|---|---|
| Two-stage sulfur unit, T/day | 30 | 140 |
| Recovery in IFP process, % | 85 | 85 |
| Overall recovery, % (2-stage Claus plus IFP) | 99 | 99 |
| $H_2S + SO_2$ in tail gas, % Vol (wet basis) | 1.5 | 1.5 |
| Total tail gas throughput, lb-moles/hr (wet basis) | 400 | 1800 |
| IFP unit battery limits investment, US$ (engineering excluded) | 140,000 | 400,000 |
| Initial load of solvent and catalyst, US$ | 5100 | 24,000 |
| Chemicals consumption, US $/hr (solvent plus catalyst) | 1.00 | 3.40 |
| Power, KW | 30 | 60 |

## IFP CLAUS TAIL GAS CLEANUP PLANTS OPERATING AND UNDER CONSTRUCTION

| Plant owner | Location | Purpose | Start-up date | Throughput, MMSCFD (design) | Sulfur recovery (design) |
|---|---|---|---|---|---|
| Delta Engineering Corporation | Lone Pine, Alberta | Demonstration | July '71* | 0.8 | 80-85 |
| Nippon Petroleum Refining Company | Negishi, Japan | Cleaning tail gas from 3-stage Claus plant | Sept. '71* | 26 | 85 |
| Idemitsu Oil Company | Japan | ditto | April '72 | 22 | 85 |
| Kyokutoh Oil Company | Japan | ditto | April '72 | 16 | 90 |
| Showa Oil Company | Japan | ditto | April '72 | 4.2 | 85 |
| Confidential | Canada | ditto | July '72 | 22 | 65 |

*Both the Lone Pine and the Negishi plants are operating smoothly since start-up at design or better levels. See the article in OILWEEK 22, No. 32, 19-24 (September 27, 1971) for full information on the Lone Pine plant.

**For more information on the IFP process for cleaning up Claus plant tail gas, contact IFP's North American office at 90 Park Ave., New York, New York 10016. Telephone (212) 986-3391.**

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IFP153L712C172

SHEET 1 OF 3

## I.F.P. SULFUR RECOVERY PROCESS

## PRELIMINARY EVALUATION DATA

Performances of I.F.P. plant - 85% of $H_2S + SO_2$ is converted into S
- 100% of free sulfur is recovered

| | | | |
|---|---|---|---|
| Sulfur unit, T/day | 100 | 100 | 100 |
| Recovery in I.F.P. process, % ($H_2S + SO_2$) | 85 | 85 | 85 |
| $H_2S + SO_2$ in tail gas, % Vol (wet basis) | 0.6 | 1 | 4 |
| I.F.P. unit battery limits investment, US$ (engineering excluded) | 340,000 | 320,000 | 280,000 |
| Initial load of solvent & Catalyst US$ | 17,500 | 12,500 | 10,000 |
| Chemicals consumption, US$/hr (solvent plus catalyst) | 1.6 | 1.6 | 1.7 |
| Power, KW | 30 | 30 | 30 |

SHEET 2 OF 3

## I.F.P. SULFUR RECOVERY PROCESS

## PRELIMINARY EVALUATION DATA

Performances of I.F.P. plant - 85% of $H_2S + SO_2$ is converted into S
- 100% of free sulfur is recovered

| | | |
|---|---|---|
| Sulfur unit, T/day | 300 | 300 |
| Recovery in I.F.P. process, % ($H_2S + SO_2$) | 85 | 85 |
| $H_2S + SO_2$ in tail gas, % Vol (wet basis) | 0.6 | 1 |
| I.F.P. unit battery limits investment, US$ (engineering excluded)<br>Initial load of solvent & Catalyst US$ | 700,000<br>40,000 | 670,000<br>37,000 |
| Chemicals consumption, US$/hr (solvent plus catalyst)<br>Power, KW | 4.3<br>80 | 4.2<br>80 |

SHEET 3 OF 3

## I.F.P. SULFUR RECOVERY PROCESS

## PRELIMINARY EVALUATION DATA

Performances of I.F.P. plant - 85% of $H_2S + SO_2$ is converted into S
- 100% of free sulfur is recovered

| | | |
|---|---|---|
| Sulfur unit, T/day | 1500 | 1500 |
| Recovery in I.F.P. process, % ($H_2S + SO_2$) | 85 | 85 |
| $H_2S + SO_2$ in tail gas, % Vol (wet basis) | 0.6 | 1 |
| I.F.P. unit battery limits investment, US$ (engineering excluded) | 3,300,000 | 3.000,000 |
| Initial load of solvent & Catalyst US$ | 200,000 | 180,000 |
| Chemicals consumption, US$/hr (solvent plus catalyst) | 21.2 | 20,3 |
| Power, KW | 390 | 390 |

## FILL OUT AND RETURN TO IFP FOR BUDGET QUOTATION

1. COMPANY ____
2. PLANT LOCATION ____

3. CLAUS PLANT CAPACITY ____ LT/D SULFUR 4. YEAR BUILT ____ 5. YEAR STARTED UP ____
6. ENGINEERED BY ____

7. ACID GAS THROUGHPUT ____ MMSCFD 8. NUMBER OF STAGES ____
9. ACID GAS ANALYSIS (VOL. %) $H_2S$ ____ $CO_2$ ____ $H_2O$ ____ $C_1,C_2$ ____
10. TYPE OF CATALYST ____
11. RECOVERY: DESIGN ____ ACTUAL ____
12. PROCESS CONTROL (SPECIFY GC, UV, OTHER) ____ CLOSED LOOP CONTROL (YES OR NO) ____
13. VARIATION OF $H_2S/SO_2$ RATIO ____ TO ____

14. TAIL GAS THROUGHPUT ____ MMSCFD @ ____ °F @ ____ PSIG 15. MINIMUM TEMPERATURE TO WHICH TAIL GAS CAN BE COOLED ____ °F 16. MAXIMUM ALLOWABLE PRESSURE DROP BETWEEN CLAUS UNIT AND INCINERATOR ____ PSI

| 17. TAIL GAS ANALYSIS | FROM 1st REACTOR | | FROM 2nd REACTOR | | FROM 3rd REACTOR | |
|---|---|---|---|---|---|---|
| | lb-mol/hr | vol % | lb-mol/hr | vol % | lb-mol/hr | vol % |
| $H_2S$ | | | | | | |
| $SO_2$ | | | | | | |
| S | | | | | | |
| $S_2$ | | | | | | |
| $S_6$ | | | | | | |
| $S_8$ | | | | | | |
| COS | | | | | | |
| $CS_2$ | | | | | | |
| $N_2$ | | | | | | |
| $H_2O$ | | | | | | |
| $CO_2$ | | | | | | |
| $O_2$ | | | | | | |
| $H_2$ | | | | | | |
| CO | | | | | | |
| $C_1,C_2$ | | | | | | |
| TOTAL | | | | | | |

18. DUTY FOR IFP PROCESS (SPECIFY ONE):
CONVERSION ____ % (FROM $H_2S + SO_2$ IN TAIL GAS) INCREASE IN OVERALL RECOVERY FROM ____ % TO ____ %
DECREASE IN STACK $SO_2$ FROM ____ PPM TO ____ PPM DECREASE IN STACK $SO_2$ FROM ____ LT/D TO ____ LT/D

19. YOUR NAME ____
20. TITLE ____
21. COMPANY ____
22. ADDRESS ____
23. CITY ____ STATE ____ ZIP ____
24. TELEPHONE (AREA CODE ____ ) ____ EXTENSION ____

**RETURN THIS COMPLETED QUESTIONNAIRE TO IFP, 90 PARK AVE., NEW YORK, N.Y. 10016 · TEL.: (212) 986-3391**

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IFP154L712C172

# APPENDIX N - WELLMAN-POWER GAS INFORMATION

# TRIP TO JAPAN, DECEMBER 2-12, 1971

## DETAILED REPORT

BY

Sheldon Meyers, Control Systems Division
John DeKany, Control Systems Division
Gary Rochelle, Control Systems Division

February 1, 1972

and manganese processes.

## WELLMAN-POWER GAS LICENSEES

We visited two operating Wellman-Lord units in Japan and discussed the process with operating personnel and design engineers. The processes are summarized in the tables below. Additional descriptive material on the units and the process in general is in Appendices 11.0. The units have been in operation since August 1971. Performance is generally satisfactory. Problems are summarized in the following sections.

Operating Wellman-Lord Units

| Location | User | Engineers | Application |
|---|---|---|---|
| Kawasaki, Japan | Toa Nenryo Kogyo | Sumitomo Chem. Eng. | Claus plant |
| Chiba, Japan | Japan Synthetic Rubber | Mitsubishi Heavy Machinery Mfg. | Oil-fired boiler |
| Paulsboro, N. J. | Olin Matheson | Wellman-Power Gas | Acid plant |

Capacity Data

|  | Gas rate SCFM | $SO_2$ rate #/hr. | $SO_2$ concentration (ppm) |  |
|---|---|---|---|---|
|  |  |  | In | Out |
| Kawasaki | 43,000 | 3300 | 6500 | 50 |
| Chiba | 128,000 | 2650 | 2000 | 200 |
| Paulsboro | 45,000 | 2500 | 5000 | 200 |
| Hypothetical 100 MW | 177,000 | 5000 | 2700 | 200 |

Purge - Degradation of the absorbent is similar to that observed at Paulsboro. At both Japanese plants the required makeup rate is about 0.45 moles NaOH/mole $SO_2$ removed. At JSR oxidation and disproportionation contribute equally to sulfate formation. At Toa Nenryo disproportionation produces twice as much sulfate as oxidation. Overall degradation at both units is 3 to 5% of the sulfur removed. Process improvements to eliminate disproportionation and reduce oxidation should reduce makeup to 0.10 moles NaOH/mole $SO_2$.

Mother liquor purged from the evaporator is used in the prescrubber, then treated with sulfuric acid and stripped with air to remove $SO_2$ and reduce COD. The solution sent to sewer is essentially sodium sulfate. Only 10 to 20% of the dissolved solids in the untreated mother liquor are sulfate or thiosulfate, the rest being sulfite and bisulfite. Even though degradation is only 3 to 5% of the sulfur removed, 15 to 30% of the sulfur is purged as sodium sulfate. MKK is piloting an alternate scheme of reducing COD by disproportionation of the waste solution at elevated temperature.

Oxidation - Both plants use scrubbers with two stages of $SO_2$ absorption and a prescrubber. Each stage consists of two sieve trays and a recirculation system. Toa Nenryo also uses a quench spray tower followed by a gas cooler before the prescrubber. The stack gas at both units contains about 5% $O_2$. JSR has 200 ppm $NO_x$ into the scrubber and 160 ppm out. At both units sulfate formation from oxidation has been about 1 kg/100 $Nm^3 O_2$.

Both licensees operated small pilot plants (600 SCFM). Mitsubishi observed oxidation of 0.8 - 1.3 kg $Na_2SO_4$/100 $Nm^3 O_2$. In a packed column Sumitomo observed oxidation of 3.0 kg without inhibitor, 1.3 kg with. Both licensees found that the rate of oxidation was directly proportional to oxygen concentration.

The oxidation inhibitor developed by Sumitomo was tested by Wellman-Power Gas at Paulsboro. It reduced oxidation 50 to 80%. The inhibitor has been used continuously at Toa Nenryo, so there is no firm evidence of its effectiveness in that application. Information received after the trip indicates that the inhibitor is EDTA (ethylenediaminetetracetic acid).

Disproportionation - There are two evaporator vessels at each plant, designed to permit double effect of steam. However, at half-load conditions only one evaporator is being used, operating near atmospheric pressure. The evaporators are designed for a residence time of 3 hours with respect to feed liquor. The amount of disproportionation should increase rapidly with temperature and proportionately with residence time. Both Japanese users are installing vacuum equipment to permit operation of the evaporators at lower temperature, thereby eliminating disproportionation. There have been no serious maintenance problems with blowers presently used to transport the $SO_2$ product.

Ash Removal - The JSR plant was not initially equipped to remove oil ash from the evaporator-absorber cycle. Ash entrained from the prescrubber accumulated and eventually caused minor plugging in the closed cycle. A semi-continuous vertical centrifuge has been installed to remove particulates from the scrubber effluent. It appears to have alleviated the problem.

Acid - The acid plant at JSR uses 100% excess air but is still significantly smaller than a plant to produce acid from S. Gas flow is about half that required for a conventional plant. Maximum gas temperature is 600°C.

Operations - JSR uses two operators. Toa Nenryo is on closed loop control by the refinery computer.

Claus Plant Alternatives - Toa Nenryo also considered use of the Beavon and IFP processes. Beavon is more expensive and IFP has technical problems.

Commercial Arrangements - The JSR plant was built by funds from MKK and the Japan Development Bank at a cost of 800 million yen ($2.4 million). MITI arranged and guaranteed the low-interest loan. JSR will buy the plant after satisfactory operation for a year.

# THE WELLMAN-LORD $SO_2$ RECOVERY PROCESS

NOVEMBER, 1971

SUMITOMO CHEMICAL ENGINEERING CO., LTD.

## I. Development and Improvement in Japan

## II. Commercial Application — Toa Nenryo Plant

This represents a brief outline of the development and improvement for the Wellman-Lord $SO_2$ Recovery process made by our company and it's commercial application to Toa Nenryo Plant.

## I. Development and Improvement in Japan

The environmental problems we have here in Japan are probably similar to those of the America. In recent years, the public opinion against pollution-air, waters, dusts, etc. has been increasingly widespread, centering on petro-chemical combinat and heavy industries crowded areas, such as areas of Kawasaki, Chiba, Sakai and so on. The emphasis given to industrial growth in the past thinking has been shifted to human health, safety and well-being for environmental protection. The enforcement by laws has been gradually prepared for pollution control; the comprehensive pollution control laws were passed in the Diet last December, transferring broad powers to local governments to regulate pollutants emissions from works or factories. The laws ~~was~~ were enacted on July 1st this year, giving one year or one year and half grace period, depending on local conditions. With this respect to the air pollution control, the permissible emission level of $SO_2$ from stacks has become severe year after year and therefore industries have realized the necessity of the $SO_2$ recovery process to direct their efforts towards it in order to meet local requirements. As one of the approaches to the $SO_2$ abatement process, a dry system was at first taken up as a pilot plant, jointly by the Government and power companies, chiefly in consideration of exit gas diffusion. And two processes were selected; one is the activated carbon process by Tokyo Power Co. and another DAP -Mn process by Chubu Power Co. and another activated carbon process was used by Kansai Power Co. later.

But these prospects are all said to be not so promising from past experiences. Some observe that a number of hitches still remain before the plant can be put to commercial use.

These capacities now are:

| | | |
|---|---|---|
| Tokyo Power Co. : | 420,000 $NM^3/H$ | (on stream early next year) |
| Chubu Power Co. : | 326,500 " | ( " ) |
| Kansai Power Co. : | 175,000 " | ( completed in September this year and at present test run continues) |

We, Sumitomo Chemical Engineering Co., richly expeirenced in the sulfuric acid plant, taking notice of this potential trend towards air pollution control, introduced the $SO_2$ recovery process from the Wellman-Power Gas Corp. (then Wellman-Lord) jointly with Mitsubishi Kakoki Company two years ago for the following reasons:

1. The Wellman-Lord process is a wet regenerative system requiring less plant area, less capital cost, compaired to the dry system.
2. The end product from the process is pure gaseous or liquid $SO_2$, which can be used as raw material for the sulfuric acid or elemental sulfur.
3. The Wellman-Lord process is able to recover at least 90% of $SO_2$ from stack gases, in excess of 97% of any $SO_3$ and acid mist, and about 90% of fly ash.
4. It is widely adaptable for use to power plants, chemical industries, oil refineries and others.

The Wellman-Power Gas, from the very beginning of the pilot plant installation to the Olin's commercial plant through the Baltimore demonstration plant, has proceeded with extensive works to obtain the process reliability, both technically and economically. On the other hand, Sumitomo began activities by installing a pilot plant of 1,000 $NM^3/H$ at Niihama just after introduction of the Wellman-Lord process. The objectives of the pilot plant were:

1. To further investigate and corroborate the Wellmna-Lord's laboratory and pilot plant data, especially in the points of $SO_2$ removal, reduction of chemical make up requirements by purge treatment and antioxidant.
2. To refine the process design, thereby further improving the process.
3. To obtain the mechanical reliability of the equipment and machinery.

The Niihama pilot plant was operated for the duration of about a year and half, first using the potassium system and then the sodium system. And also the plant treated gases from the sulfuric acid tail gases to oil fired boiler using the high concentrated sulfur of 5%. Thus, the extensive test programs were conducted and the pertinent data the plant could give were all collected, The results on basic process chemistry proved to be encouraging and satisfactory. The research and development tests thus carried out by us led to the award of the contract by Toa Nenryo Company for the first Wellman-Lord $SO_2$ recovery plant last July.

## II. Commercial Application — Toa Nenryo Plant

Toa Nenryo Company, one of the leading oil company in Japan and incorporated with Esso and Mobil of the U.S.A. with each 25% shareholder, installed the sulfur recovery plant (Claus unit) as part of the indirect desulfurization plant at Kawasaki, Kanagawa Prefecture. The Kawasaki area is under the severest regulation for pollution control because of heavy industries covering oil refineries and iron steel densely congested and the stack height is limited as low as 50 meters or so because the Haneda air port is located in the close neighborhood of the Kawasaki area.

In such a circumstance, Toa Nenryo made the extensive study of the $SO_2$ recovery process to treat tail gases from the sulfur recovery plant and finally selected the Wellman-Lord process as the most suitable and advanced technology after evaluation of the process effectiveness. They appreciated the Sumitomo efforts to conduct tests by the Niihama pilot plant and finally gave us an award to proceed with designing, engineering and construction of the plant as a general contractor last July, based on the Wellman-Lord basic design. The process is a sodium based absorption which will recover the $SO_2$ for re-use in the sulfur recovery plant. The plant was completed early July this year as expected but the plant start-up was delayed more than a month because Toa Nenryo decided on consideration that the Japanese market surrounding the oil products was so badly depressed.

But the plant now is operating successfully absorbing $SO_2$ in excess of the original design specifications and this is the first commercial installation of the Wellman-Lord's $SO_2$ recovery process in Japan and further constitutes a milestone to the air pollution control.

The outlines of the Toa Nenryo plant are as follows:

Basic design conditions

Gas volume: 67,200 $NM^3/H$
$SO_2$ concentration: 7,600 PPM
Temperature: 538°C
Pressure: 20 mm $H_2O$
End product of $SO_2$: Max. 200 PPM

The process itself is principally the Wellman-Lord process except the pretreatment of gases. (The process flow is given on the attached sheet for reference.)

It is, first, necessary to cool down the gases of high temperature. The gases containing rich $SO_2$ and other components are led into the waste heat boiler where steam is generated to be available for use and then introduced into the spray tower by the blower to be cooled down with water spray. The cooled-down gases are sent to the pre-scrubber at the absorber bottom at an appropriate temperature by way of the indirect gas cooler. Following the absorber section to the $SO_2$ cooler through the chemical section, the main stream is as covered by the Wellman-Lord process. Here, we present you some characteristics with the Toa Nenryo plant:

1. $SO_2$ emission at the absorber top.
   70~150 PPM (Inlet $SO_2$ 6,000PPM)
2. The absorber is of sieve tray type.
3. End product of $SO_2$ is returned to the sulfur recovery plant.
4. Antioxidant developed by Sumitomo Chemical Co. is used to inhibit the sulfate formation, thereby reducing chemical requirement.

5. Materials

Rubber lining or FRP used where temperature is relatively low. Stainless steal used where temperature is relatively high or corrosion may occur.

The plant started up mid-August after a month postponement as aforesaid and up to date it shutdowned twice, the first due to the failure of the gas duct from the absorber to the central stack and the second the sewer system. We experienced some minor mechanical problems with it but we have cleared them up through a joint effort with Wellman-Power Gas and the client.

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